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CONFERENCE BOARD OF DIRECTORS

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FIRST SESSION, Wednesday, May 21 - 9:00 a.m.

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CHAIRMAN: John F. Utley, National Director--Regulated Business Practice, Deloitte Haskins and Sells

SPEAKERS: Heber P. Hardy, President, National Association of Regulatory Utility Commissioners

Richard Everett, Senior Economist
Chase Manhattan Bank
(No Paper Available)

Arnold E. Safer, Ph.D.
Resource Planning Associates, Inc.

A REGULATORY VIEW OF THE ECONOMIC OUTLOOK FOR REGULATED UTILITIES

Heber P. Hardy
President
National Association of Regulatory Utility Commissioners

The economic outlook for regulated business in the United States can be likened to near the end of a furious noisy thunderstorm as the billowy clouds begin to separate and the bright sunlight begins to send shafts of light to the earth - clouds with silver linings.

The 1970's have been characterized as the decade of debate on the subject of energy. The 1980's may be the decade of action and resolution as a national energy policy is determined and implemented. The vulnerability of our economy to the thin line of tankers from the middle east and the shortages of domestically produced energy (as measured against the wasteful lifestyle of which our people have become accustomed to) caused the very foundations of our economy and way of life to shake during the 70's.

The opportunity of the 80's is to complete the transition from a period of inexpensive energy (1960's) with its attendant wasteful practices to a period (1980's) of adequate, reliable and usable energy safe from the uncertainties of foreign political powers and acceptable to the environmental, social, political, and economic concerns of our nation. Needless to say, such a task will not be easy, painless or inexpensive. Cooperation and accommodation will have to be emphasized and practiced. Special interests will have to be recognized and persuaded to compromise and sacrifice if necessary to achieve desired goals.

There must be a better and more effective effort to inform and convince the general public that basic economic principles must be permitted to function in order to determine which energy resources will be used and at what prices. Politically determined prices will not provide the incentives or the means to develop adequate energy resources.

Senator Mike Gravel of Alaska recently stated that government ..."cannot give us a risk-free existence. It cannot duplicate the independent creativity of thousands of individuals and small firms. And it cannot replace the market system and decide for millions of people what is best for each, the way each can decide for himself. It cannot distribute goods and products of the nation as effectively, or even as fairly, as the private enterprise system, because it cannot duplicate for itself the incentive of profit and the discipline of loss or the freedom of the consumer choice mechanism ..."

There has been a great amount of emphasis and publicity about the protection of consumers against the rising costs of energy. There has been a lot of emphasis and publicity about insuring that energy producers and energy purveyors (including public utilities) do not earn excess profits. There has been too little emphasis upon the long range desirability of consumers having available for their use sufficient energy to meet their perceived needs. There has been too little emphasis upon the absolute necessity of economic incentives to entice individuals and institutions to invest their savings in companies who are willing and capable of producing, transporting and distributing energy in a usable form. There has been too little public recognition and understanding that public utilities must compete in the capital markets for money to build necessary facilities to provide utility services, and that in order to reasonably compete they must be financially healthy. There has been too little recognition on the part of public utilities that they must not only operate as efficiently and cost-effectively as possible, but they must also listen to consumers and patiently and honestly try to convince them that they are working in the best interest of both present and future consumers.

Public utility regulators must face up to the fact that they are economic regulators and not political or social regulators. Their concern for consumers should be that they are served by efficiently operated utility companies at the lowest rates possible while recognizing that a critical and substantial cost component is the cost of money and that the cost of money is less for a company which is perceived by potential investors as financially healthy and has a reasonable opportunity of earning its allowed rate of return.

Patricia Shontz, economist and editorial writer for the Detroit News, said in 1973:

> "The long history of public utility regulation breeds what we might call 'the regulatory mentality', a bland management listlessly protecting company interests and a hackneyed bureaucracy paying lip-service to the public interest. When management gets lazy about fighting for their profitable survival and the realities of market forces, and when bureaucrats become fascinated with the petty exercise of their powers, the industry and the public interest are in deep trouble. This is the kind of situation that produced the mystique of artifically cheap power, a policy which has been counter-productive for more than a decade and which was never really justified, since it obscures the principle of full-cost pricing. The rationale of cheap energy is the delusion that there is a free lunch."

Public utilities, as well as their customers, are the victims of rising energy costs and inflation. Yet the public perceives public utilities as the enemy and the most visible and direct entity which charges them higher and higher prices for essential commodities and services. When a utility files an application to recover its increased costs, then the public frustration and anger shifts to the regulatory agency which is perceived by the general public as having the power to deny increases even if such increases are absolutely justified. Unfortunately, many regulators during the 70's were more interested in denying increases or at least reducing them substantially than they were in providing incentives for utilities to provide good and reliable services to current as well as future customers.

It is my belief that more state regulators now consider that financial health is the key to an efficiently operated utility which genuinely concerns itself with the interests of its customers as well as its stockholders. We are very concerned that utilities are in a position to sell stock and issue bonds in sufficient amounts and at reasonable costs in order to meet the needs of all consumers. However, we are also concerned that utilities vigorously and conscientiously avoid all unnecessary costs by promoting wise and efficient use of energy by themselves and their consumers; by adopting rate designs and load management techniques which reduce peak demands and excess capacity; by obtaining all fuels, materials, supplies, services, labor, etc. at costs as low as possible; by challenging every proposed regulatory and governmental action which will impose costs above the anticipated benefits; by using the most up-to-date cost effective methods of determining the need for and timing of new facilities to provide service; and by preparing and presenting clear, precise, understandable, justifiable, reasonable and well-documented cases when seeking approval of increased rates, financing, or building new facilities.

The statement by Patricia Shontz in 1973 that: "Even today, in an age of energy enlightenment, regulatory bodies still believe their highest calling is to put a zero price tag on power and please never mind that the supply would be zero as well"...is certainly not generally true today. For the most part, we have recognized the need for and soundness of the principle that utilities need timely and adequate rate relief in order to do their jobs properly.

Ken Hollister, First Vice President of Dean Witter Reynolds, Inc., recently indicated that even though investors still have serious concerns about the ability of utilities in all jurisdictions to earn their authorized rate of return he concluded that: "Despite all the thrashing about, it can be stated that regulation is doing its job. The investor is placing sufficient funds into the industry to permit completion of the construction programs approved by management; the customer, although disgruntled, is receiving service. On balance, an uneasy truce exists." Mr. Hollister further stated: "Utility regulators today are engaged in an uphill battle. With only a few exceptions, they and their support staffs are thoughtful and trying to find answers to problems that did not exist heretofore. Like the industry, they are seeking to achieve a level of credibility with diverse audiences. In that, for better or worse, they will affect the shape of the future; they are a powerful group. Both the customers and the investor must remain alert to this use or abuse of power."

The key to the economic future of regulated utilities is to build upon the "uneasy truce" mentioned by Mr. Hollister. Whether the silver linings of the storm clouds grow brighter or close together and renew the storm is largely dependent upon whether utilities and regulators can honestly and competently deal with revenue and capital requirements on a sound economic basis. In order to do that utilities must convince their customers that they are operating efficiently and doing everything in their power to hold operating and capital costs to the lowest level possible consistent with providing adequate service. Regulators must demonstrate to ratepayers that the increases allowed are reasonable and required in order for the utility to provide adequate service and to attract capital at reasonable rates. Both must take advantage of every opportunity to teach basic regulatory economics to every person who will listen, particularly political leaders, so that political regulation is not substituted for economic regulation. The profit motive has got to be retaught as the primary motivation for capital formation and investment. It must be understood that regulation is intended to prevent excess profits for natural monopolies, but it should not be used to stifle the desire or ability of utilities to properly serve current and future customers.

It is not easy to achieve a balance between the interests and concerns of utilities, their investors and their customers. It is my belief that a straightforward and honest approach is best. The "golden age" of regulation will have arrived when utilities consistently request only what they really need, regulators are assured that what is requested is really needed and reasonable and therefore should be granted and all customers and investors are satisfied that they have been treated justly. Now I doubt that all customers and investors will ever be satisfied, however I believe that the narrower the gap between requests and grants, honestly and competently arrived at, the greater the possibility of satisfying customers and investors.

It is unfortunate when a utility requests substantially more than it can justify and it is equally unfortunate when a commission denies a part or all of a rate request without good and justifiable cause. The public gets the impression that the utility is trying to rip them off by unreasonable requests and that the commission has the power and should in every case deny the increase in part if not entirely. The public also tends to believe that if a commission does not deny all or a substantial part, it is because it is incompetent or improperly influenced by the utility. Such perceptions have given rise to special agencies or offices to represent the consumer and has turned rate hearings into adversary proceedings, labeling the utility as a plaintiff and the consumers as defendants.

A decision of a commission which grants a rate increase is considered to be in favor of the utility and against the defendants and the integrity of both the commission and the utility is diminished. The role of a regulatory commission needs to be taught, by every means available, as one of determining the revenue requirements of a utility for the benefit of all consumers. The "crisis of confidence" in public utilities and public officials must be addressed and resolved. The media also must be educated and corrected when necessary. Above all, regulators and utility personnel must act above reproach and earn the confidence of their constituents.

Serious consideration should be given by utilities and regulators to ways and means of softening the impact of large increases all at once upon ratepayers. More and more people are understanding the reasons behind increasing costs of oil and natural gas, but when they receive 25 to 100% increases, their budgets are strained beyond their ability to adjust and they become frustrated and strike out angrily at utilities and regulators.

States are trying to develop innovative methods of balancing the interests of utilities and consumers. Deferred energy accounting as now practiced in the State of Nevada provides 100% delayed recovery of increased fuel and purchased power costs through a monthly surcharge over a period of time comparable to the deferral period. At the same time that recovery of deferred costs are authorized we also authorize the base unit energy cost to be updated to current costs and to be included in the base tariff rates. Over or under recovery of deferred costs are carried over to the next open deferral period. It is our hope that such a procedure will provide reasonably timely and full recovery of fuel and purchased power costs and will spread out the impact of substantial increases over time.

Another cause of a large increase in rates to customers at one time is the rate of return requirements of a large generating facility when it goes into service. Many states, including Nevada, have permitted some portion of construction work in progress in rate base in order to ameliorate the magnitude of the impact when the unit goes into service and also to reduce the amount of interest during construction which becomes a part of rate base.

Other states have authorized indexing plans designed to encourage efficiency and have rewarded it by timely and adequate rate relief. Others have reduced regulatory lag by using foward looking test periods and deciding cases in a shorter time. More regulators are recognizing the need for utilities to have a better opportunity to earn the rate of return authorized during inflationary periods.

Utilities might improve their image in their communities by encouraging greater numbers of their consumers to become stockholders. It has been said that where your treasure is, there will be your heart also. At least, there would probably be fewer customers who allege that the utility is earning excessive profits.

The experience of the 70's has been a great teacher for regulators and utilities. If we have learned our lessons well the future of regulated businesses will be brighter and less adversary. Further, I believe consumers will also be better served.

I don't mean to imply by my comments that utilities will not be faced with serious economic problems in the future which may be as great or greater than those of the 70's. My feeling is that state regulators are better prepared to deal with such problems as a result of our past experience.

ENERGY AND THE ECONOMY: AN INTERNATIONAL PERSPECTIVE

Dr. Arnold E. Safer
Principal
Washington, D.C.

Introduction

Thank you very much for having me.

I am going to tell you about some of my views, which may differ from some of the things you have heard, both in the general literature or press on the subject and I think some of the views expressed here today. I think I express a peculiarly American point of view, so you have to forgive my provinciality.

First, I would like to say a bit about the question of uncertainty. People often ask me: Is there an oil-shortage? And being an economist, of course I hedge my response. I say Yes, No and Maybe. And that, to some extent, is reflective of the kind of uncertainty which I think we all face. Being a professional forecaster and economist, I have learned to live with it, for better or for worse, but I am not sure that governments can. I think oil companies generally know how to, -larger companies dealing with the uncertainties in one way, smaller companies dealing with the uncertainties in other ways.

When I say Yes, No and Maybe to that question; what I mean is: Yes, I think that in the very short run the shortfall in world oil production as a result of the political events in Iran, in late 1978 and early 1979, very clearly caused decline in world supply at that time.

This had the effect of generating expectations in the marketplace which drove prices significantly upward. As a result, or partially as a result of that increase in price, other OPEC countries and non-OPEC countries, where planned production had been coming on-stream, served to give us the necessary supply-response. To some extent, there was also a demand-response to higher prices, but lagged and we only see it now in late 1979 and early 1980. That is, at least in the United States we are heading for a fairly severe recession.

So, I do think that in the short-run sense, yes we do - or did (if you like) - have an oil-shortage. The intermediate term, looking out to 1982-1983, I really do not believe we will have such a shortage. My own guesses (which I have been making now for several years) suggest, that demand for oil, especially at the new price level we are faced with, will grow at a somewhat lower rate than new non-OPEC supplies, and therefore, barring another political upheaval, we are unlikely to get another severe oil crunch.

I might make one observation here: if a small, two to three percent, shortfall in the early months of 1979, led to a 60 percent increase in price, why perhaps, would not a 2 percent surplus at some time in 1980 lead to a 60 percent decline in price?

I leave that for you to contemplate and raise another pointed question with you; the question of monopoly. Primarily from an

American point of view, we do not particularly like them or tolerate them. I think Europeans may have a more benign attitude towards them than we Americans.

Then the "maybe". Is there an oil-shortage? Well, maybe and that is the longer-run question which I really do not think anybody knows the answer to.

I think that it is more a question of: Will the price rise so high as to put such severe a strain on western economic growth, as to change our society in a fundamental way? To put the western economies into a depression? Some of you may remember that time; I only remember by history or by reading. Those are some of the real difficult questions which we really do not know the answer to. (Clearly one response is this idea of energy conservation.)

So, we live in an uncertain world. As I said, I do forecasting - and this uncertainty reminds me of one joke which I want to tell you before I get into my prepared slides. It goes like this: This fellow is walking down the street in Belfast (Ireland). Someone sticks a gun in his back and says: "Are you a Catholic or are you a Protestant"? Being in Belfast, with either answer, he could get shot. So he thinks for a moment and he says: "I am Jewish". The gunman spins him around and says: "I must be the luckiest Arab in Belfast". (One of those damned if you do, damned if you don't, situations).

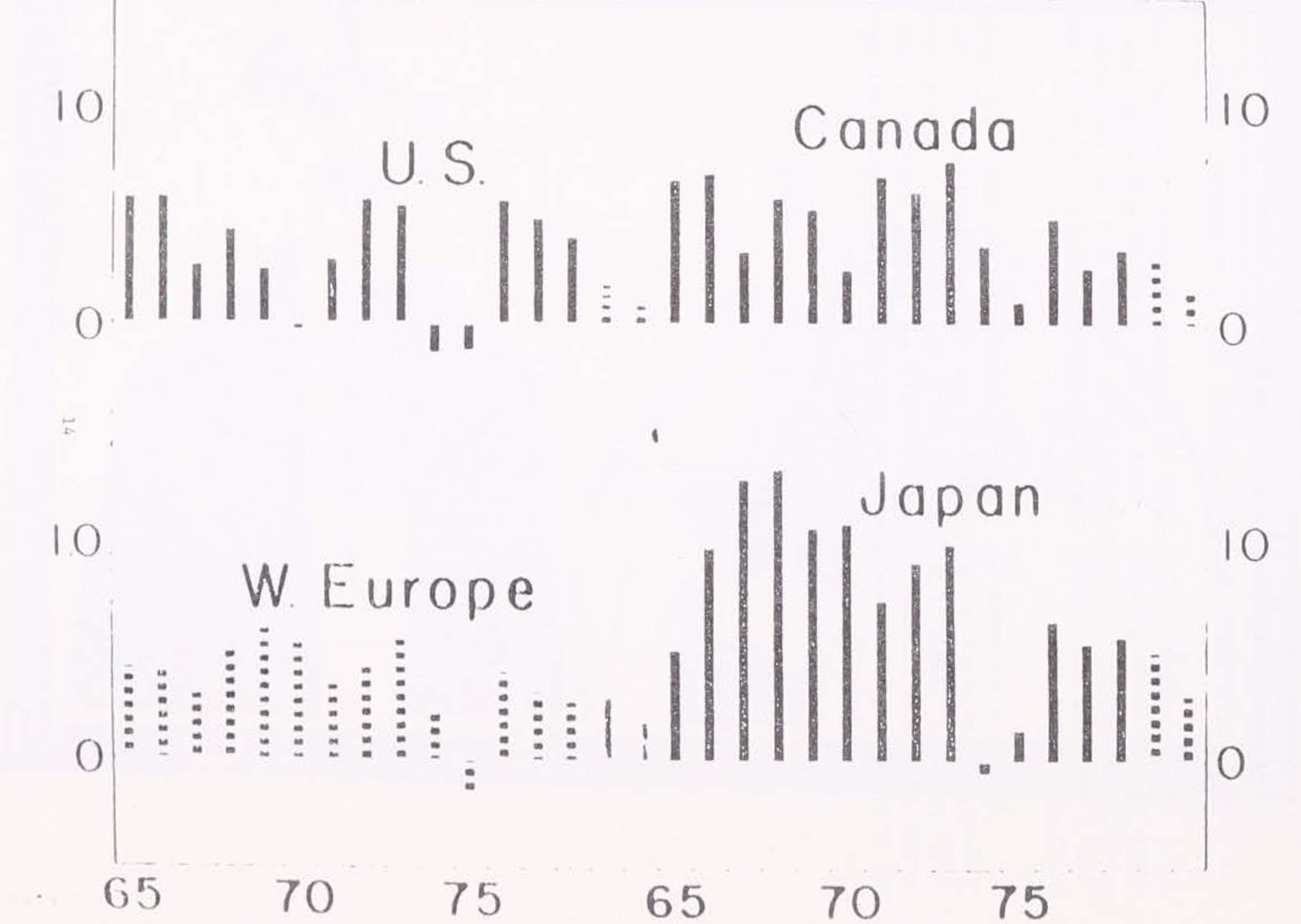
I will make three key observations with these slides. First, as we talk about conservation, I want to raise some questions about the notion of productivity and what conservation could imply concerning changes in the productivity, of labor in particular. The second area which I will cover has to do with the policy responses of different governments in terms of the macro-economic/business-cycle adjustments to the problems of high oil-prices. Third, I will give you some details on the world oil outlook, which is a little different from most of the things that you probably read in the general press.

Slide 1:

You may remember September 1974, President Ford had a "Whip Inflation Now" campaign, portrayed by the win-button.

We thought then that inflation was our No. 1 problem; that was September and October of 1974; in fact we were heading rapidly toward a very deep recession. That may very well be the case today, in late 1979 and early 1980.

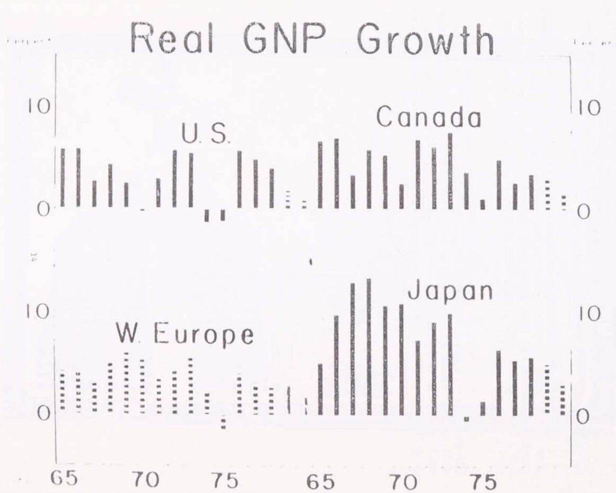
Real GNP Growth



Slide 3:

Look at the lower part of this graph: EEC-oil consumption, relative to real GNP, similarly for the United States. Although there has been some criticism of the United States in certain international circles, concerning its effort to conserve, I think the data would suggest that, while perhaps the effort on the part of the EEC since 1973 has been greater and the numbers have come down somewhat faster, both economies have approximately equal ratios of oil-consumption relative to real GNP.

I think there are some misconceptions concerning the way the United States goes about it. We do it in different ways but I think our results are not too different from the general international picture.



Slide 3:

Look at the lower part of this
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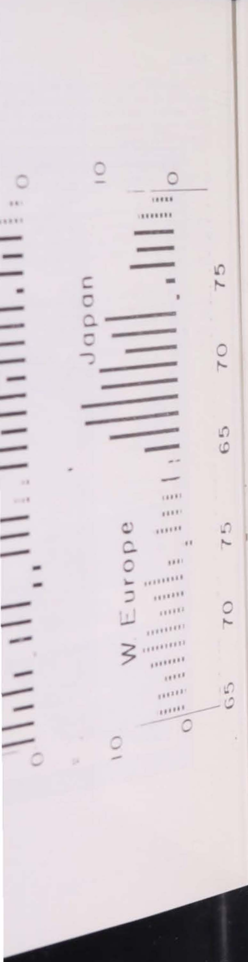

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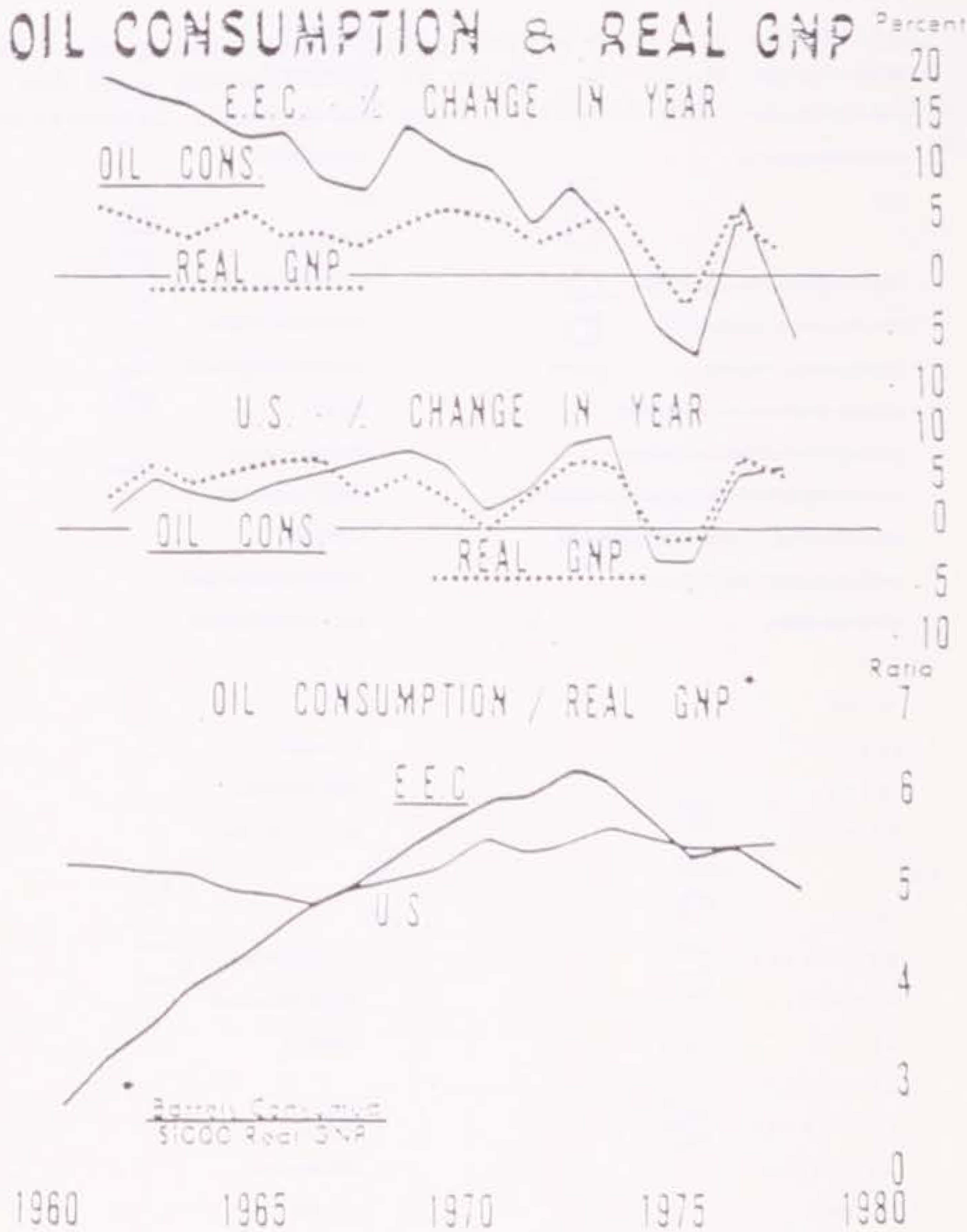
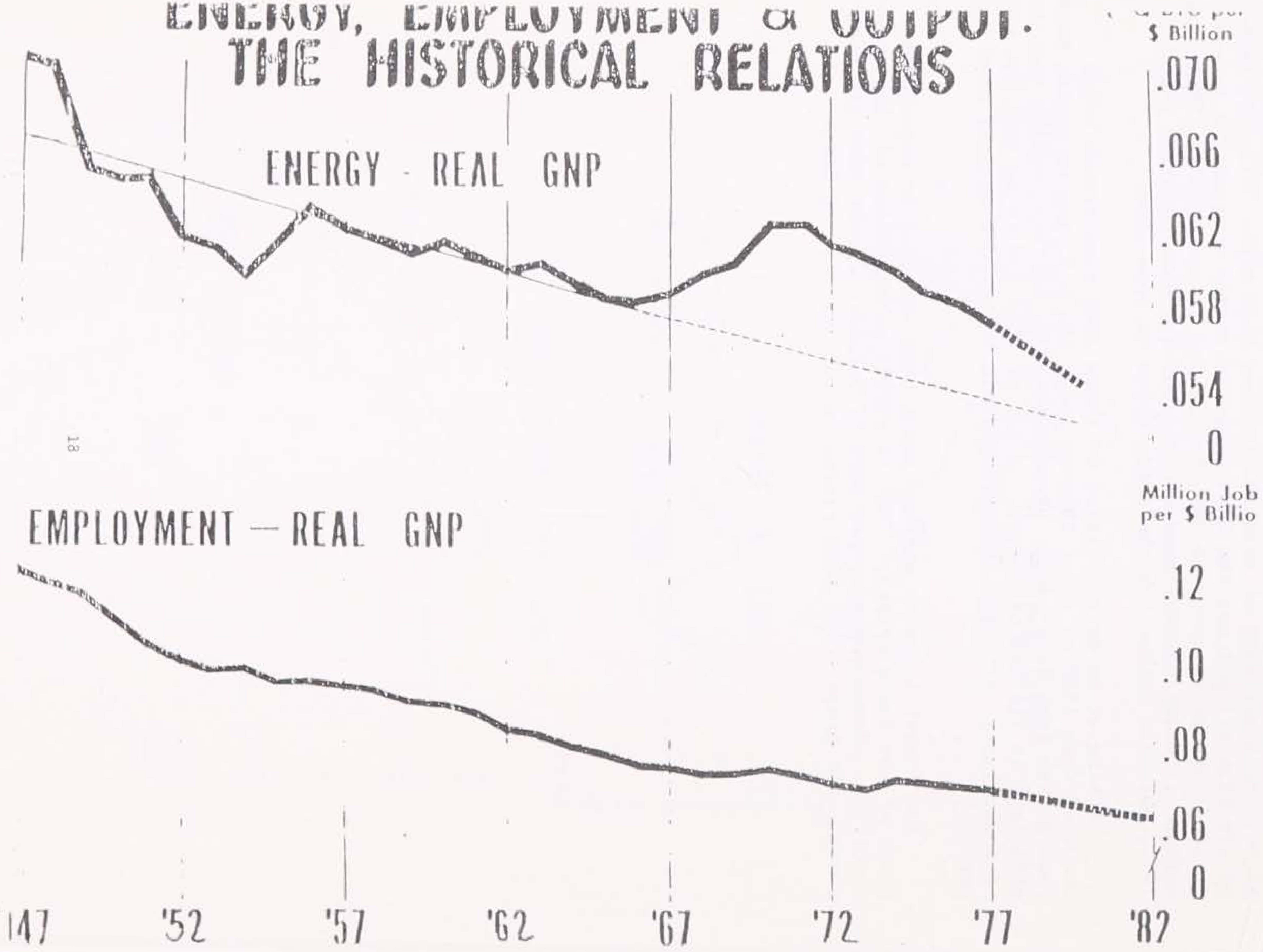

OIL CONSUMPTION & REAL GNP
Percent
E.E.C. - % CHANGE IN YEAR
OIL CONS.
REAL GNP
U.S. - % CHANGE IN YEAR
OIL CONS.
REAL GNP
20
15
10
5
0
5
10
10
5
0
5
10
Ratio
OIL CONSUMPTION / REAL GNP*
E.E.C.
U.S.
7
6
5
4
3
0
$1000 Real GNP
1960
1965
1970
1975
1980

Slide 4:

Focusing on total energy relative to GNP, for the United States alone, the upper part of this chart shows that since 1972-1973 (even before high oil-prices) the U.S. began to reduce some of the excesses in total energy relative to GNP that it had in the 1960's. There are certain (I think unique) American reasons why this occurred prior to 1973, but then notice how the ratio began to come down.

Looking at an extrapolation of those long term trends which occurred from 1930 to about 1966 or 1967, the U.S. may be moving back toward that long term trend. From 1966-1973, the U.S. became much less efficient in its use of energy. A lot of this had to do with the size of powerplants, from the increasing scale to the decreasing, over that period.

But I want to raise another issue here and that is employment (look at the lower graph). That is simply a reflection of labor productivity. Fewer workers, per unit of output. If one used its reciprocal, the graph would show rising output per unit of labor.


ENERGY, EMPLOYMENT & OUTPUT:
THE HISTORICAL RELATIONS
ENERGY - REAL GNP
EMPLOYMENT — REAL GNP
$ Billion
.070
.066
.062
.058
.054
0
Million Job
per $ Billio
.12
.10
.08
.06
0
'47
'52
'57
'62
'67
'72
'77
'82

Slide 5:

I simply then ask myself what happened to energy versus employment? I made a little calculation here and I said to myself: "How many (British terminal units) BTU's of energy do we need to sustain a million jobs in the United States economy? (We have about a hundred million jobs in the U.S. economy.) The term "need" may be too strong a word, I will not argue about it, but certainly the amount of energy consumed historically per unit of labor was related to the growth-rate in productivity.

That is, one could argue that it takes a certain minimum amount of energy to sustain productive employment. Simply making jobs, without getting the historical increases in productivity is inflationary. I would agree, how one measures productivity is an important element, and I think the environmentalist speaker this morning raised some questions which touched on that (what one means by output, which affected the meaning of productivity).

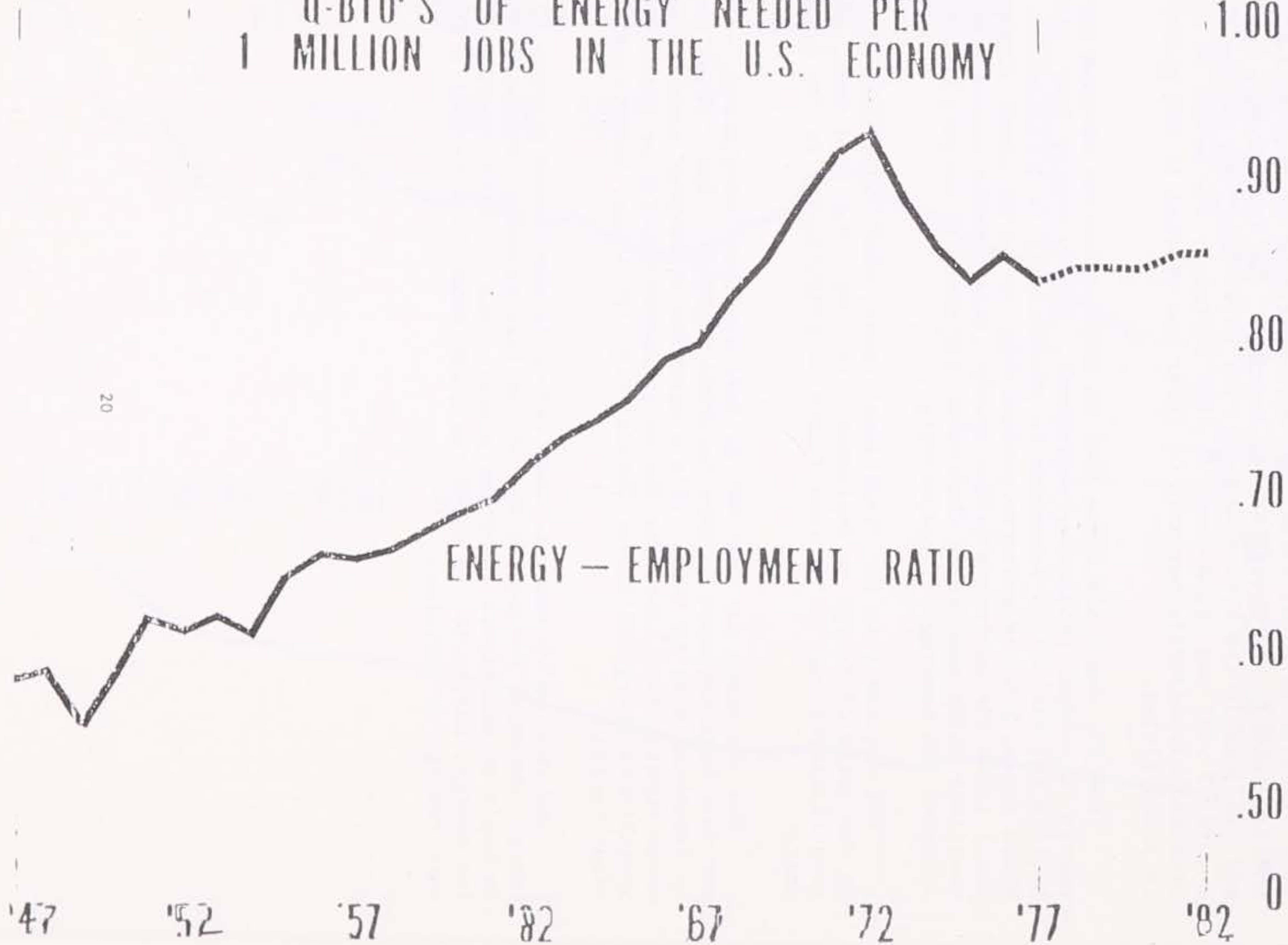
But certainly in the traditional sense, what we've seen is that as the ratio of Energy to Employment (to jobs), has come down, and even flattened out, we've seen a loss of productivity in the United States.

Now one might say that may be just spurious correlation, - they may just have happened to have occurred together. But I think there is something more to this. It's a question of whether conservation means substituting Labor for Energy-Intensive Capital or whether one substitutes Energy-Efficient Capital for, let's say, Energy-Inefficient Capital.

And what we've seen, to some extent in the United States, as the energy-consuming businesses operate at full capacity, is the tendency to begin to substitute labor for energy. And if labor is substituted for energy, having to pay labor the going wage-rate, becomes a direct pass-through to inflation.

ENERGY & EMPLOYMENT

Q-BTU'S OF ENERGY NEEDED PER
1 MILLION JOBS IN THE U.S. ECONOMY

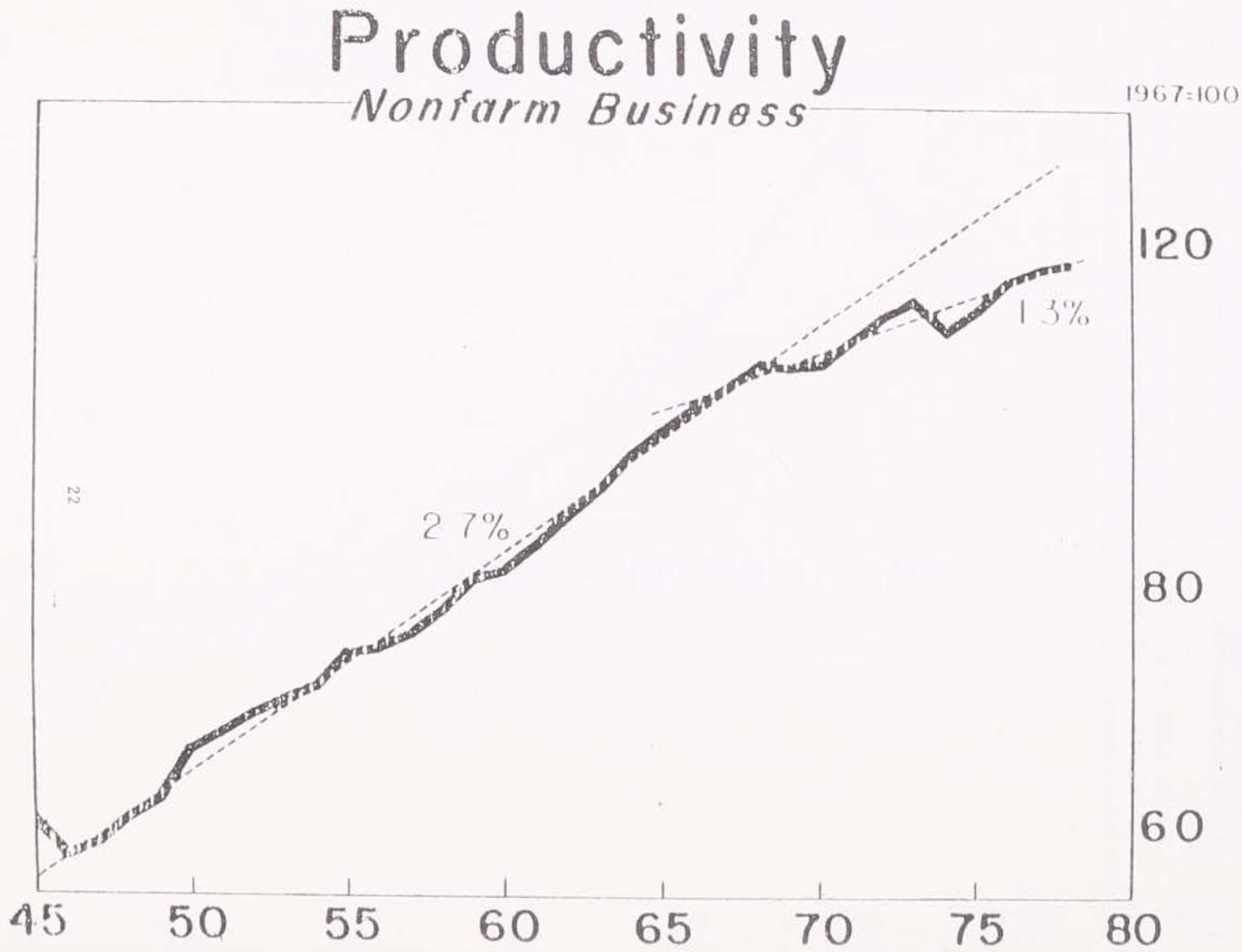


Slide 6:

This chart shows the decline in productivity gain between the pre-OPEC period and the post-OPEC period.

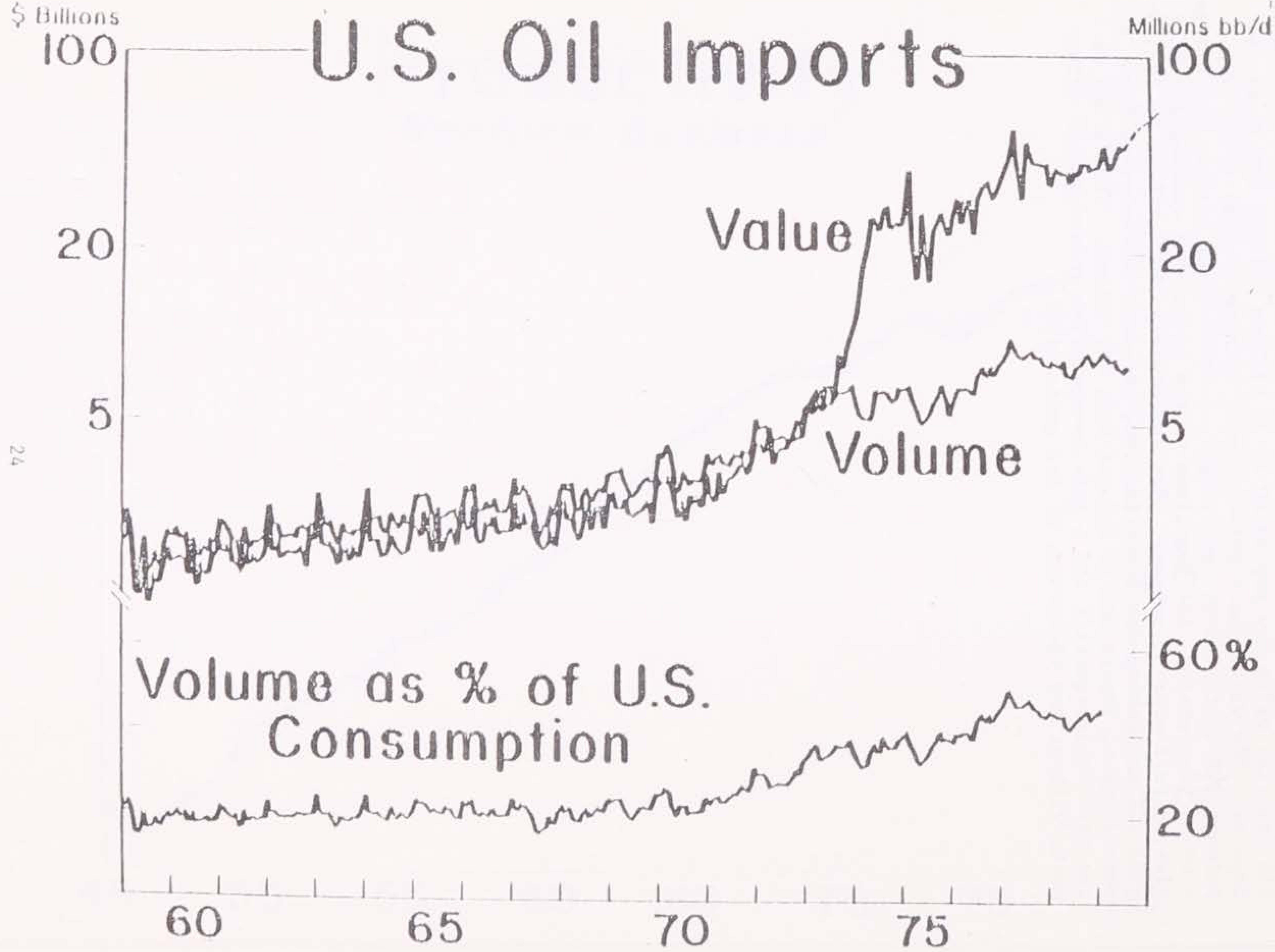
In 1978, the U.S. had a minor increase, perhaps 0.5 percent; so far in 1979, productivity is in fact down, -negative.

I don't know the answer to this question, but I do think that as part of this notion of energy conservation, we will have to take into account how substitution of these factors of production takes place.


Productivity
Nonfarm Business
1967=100
120
80
60
2.7%
1.3%
45
50
55
60
65
70
75
80

Slide 7:

This chart shows the U.S. oil-import picture. Just go back to the early 1960's and 1970's when the U.S. was spending under $5 billion for oil imports; we're now paying 60 to 70 billion dollars for those oil-imports. The volume as a percentage of consumption has moved from perhaps 20% to the 45-percent range. I think that, barring a prolonged economic depression, the magnitude of the percent of consumption will rise to well over 50 percent. Not immediately, but perhaps by 1982 or 1983. I am looking for a decline over the next two years in terms of percentage of import due to reduced U.S. oil demand. That's why we can have import-quota's and a more co-operative international agreement, without any violations of the quota limits.

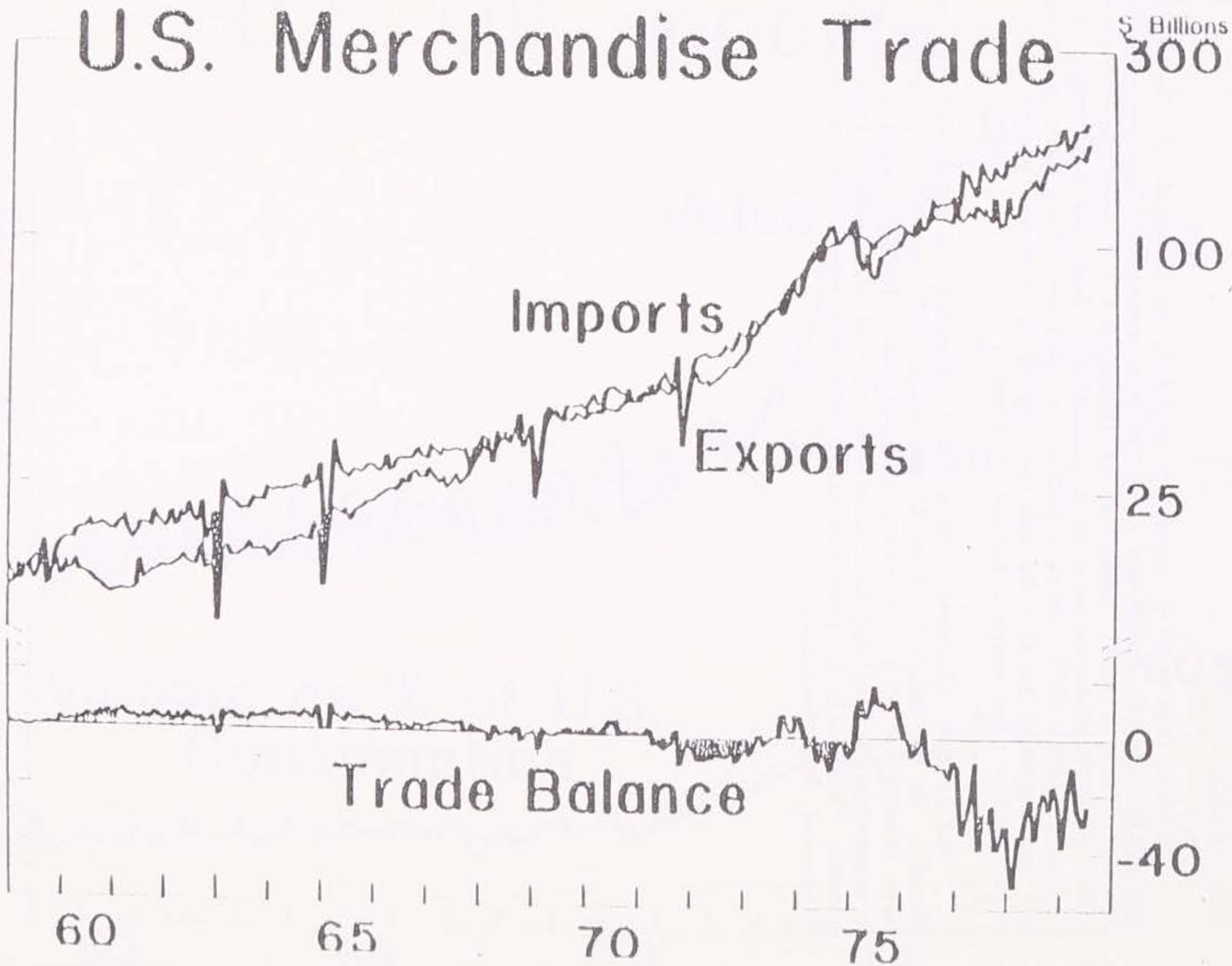

U.S. Oil Imports
$ Billions
100
20
5
Millions bb/d
100
20
5
60%
20
Value
Volume
Volume as % of U.S.
Consumption
60
65
70
75

Slide 8:

As a result of these massive oil-imports, the U.S. total trade balance, has gone into deficit. Now notice what happened in 1975. The U.S., in fact, had a trade-surplus, even though it was importing lots of oil.

It went into a deep recession in 1975, as did much of the rest of the world. But it turns out that the U.S. exported high technology and agricultural goods, where as we imported a lot less oil and consumer goods because we were in a recession. Then the U.S. began to recover, -1976, 1977, 1978, - and we started importing more and more oil and consumer goods. We ran our Engine of Economic growth much more rapidly than Western Europe or Japan.

And so the U.S. went into a fairly significant trade-deficit as a result. We may begin to turn it around in 1979 as we get a little more growth out of Western-Europe and Japan. The U.S. will experience a recession in 1980 and that will temporarily change this trade balance around. This will be good for the dollar and other such international financial considerations.

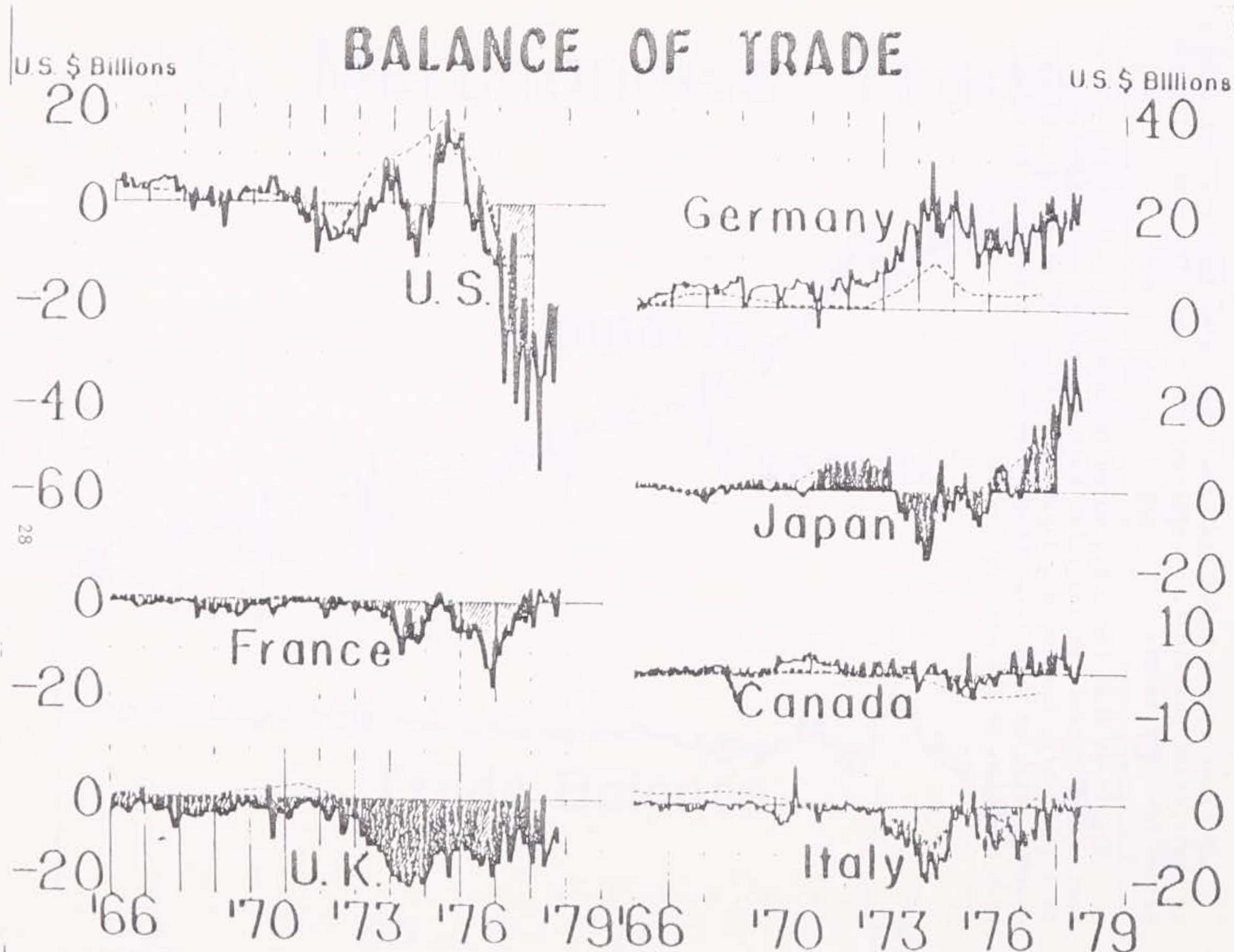

U.S. Merchandise Trade
$ Billions
300
100
25
0
-40
Imports
Exports
Trade Balance
60
65
70
75

Slide 9:

Relative trade-balances are important. Note the U.S. large negative, versus Germany and Japan with very large positive, $20 billion-30 billion for each.

The rest of the industrial countries maintained reasonable balance in their trade positions, or at least their deficits were neither sustained nor very large.

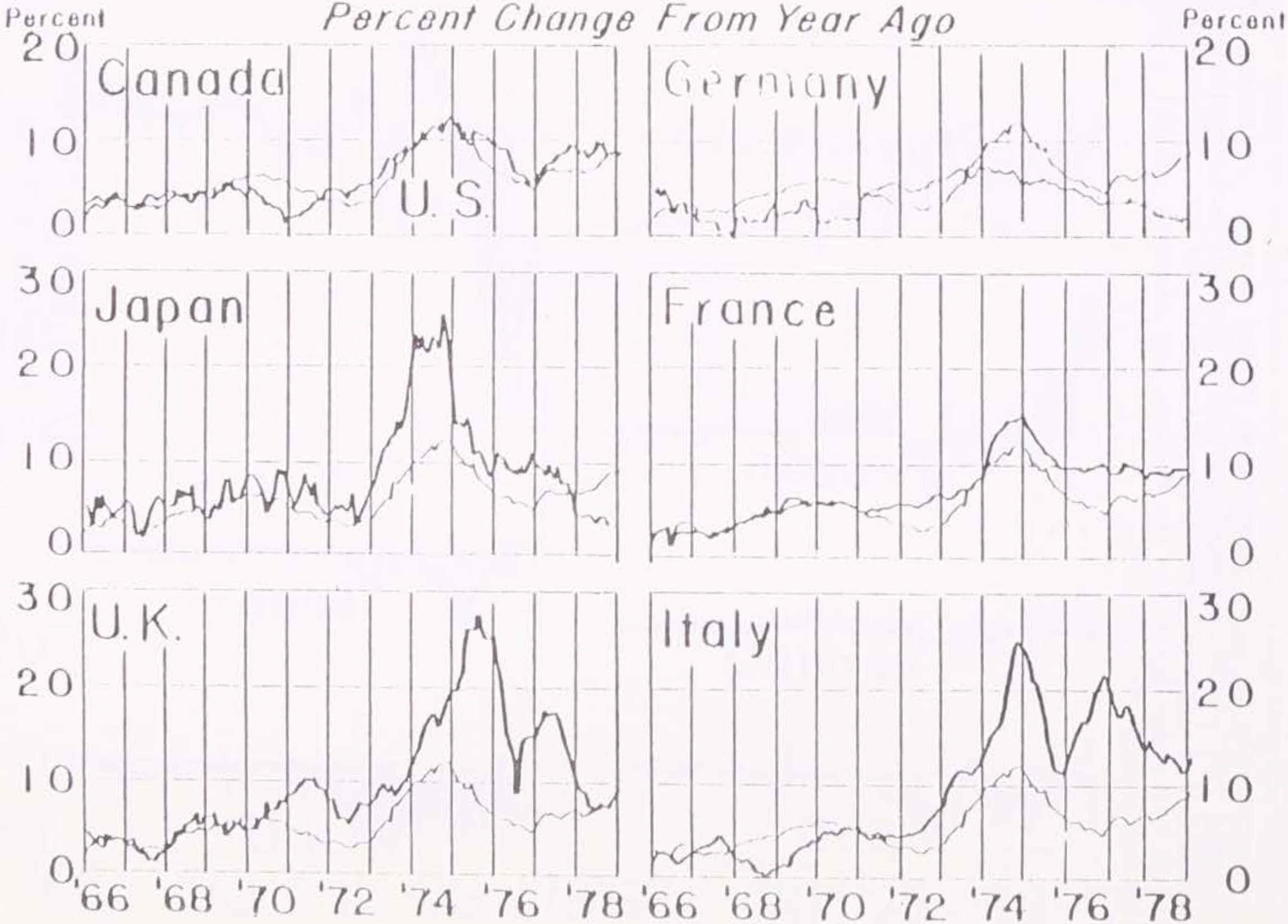
How is it that the U.S., which imports only half of its oil and kept price controls on its other half, sustained such huge trade deficits, while Germany and Japan, importing all of their oil, were able to chalk up such large trade surpluses? I will try to answer that question in the next few slides.


BALANCE OF TRADE
U.S. $ Billions
U.S. $ Billions
20
0
-20
-40
-60
U.S.
Germany
Japan
0
-20
France
Canada
0
-20
U.K.
Italy
40
20
0
20
0
-20
10
0
-10
0
-20
'66
'70
'73
'76
'79
'66
'70
'73
'76
'79

Slide 10:

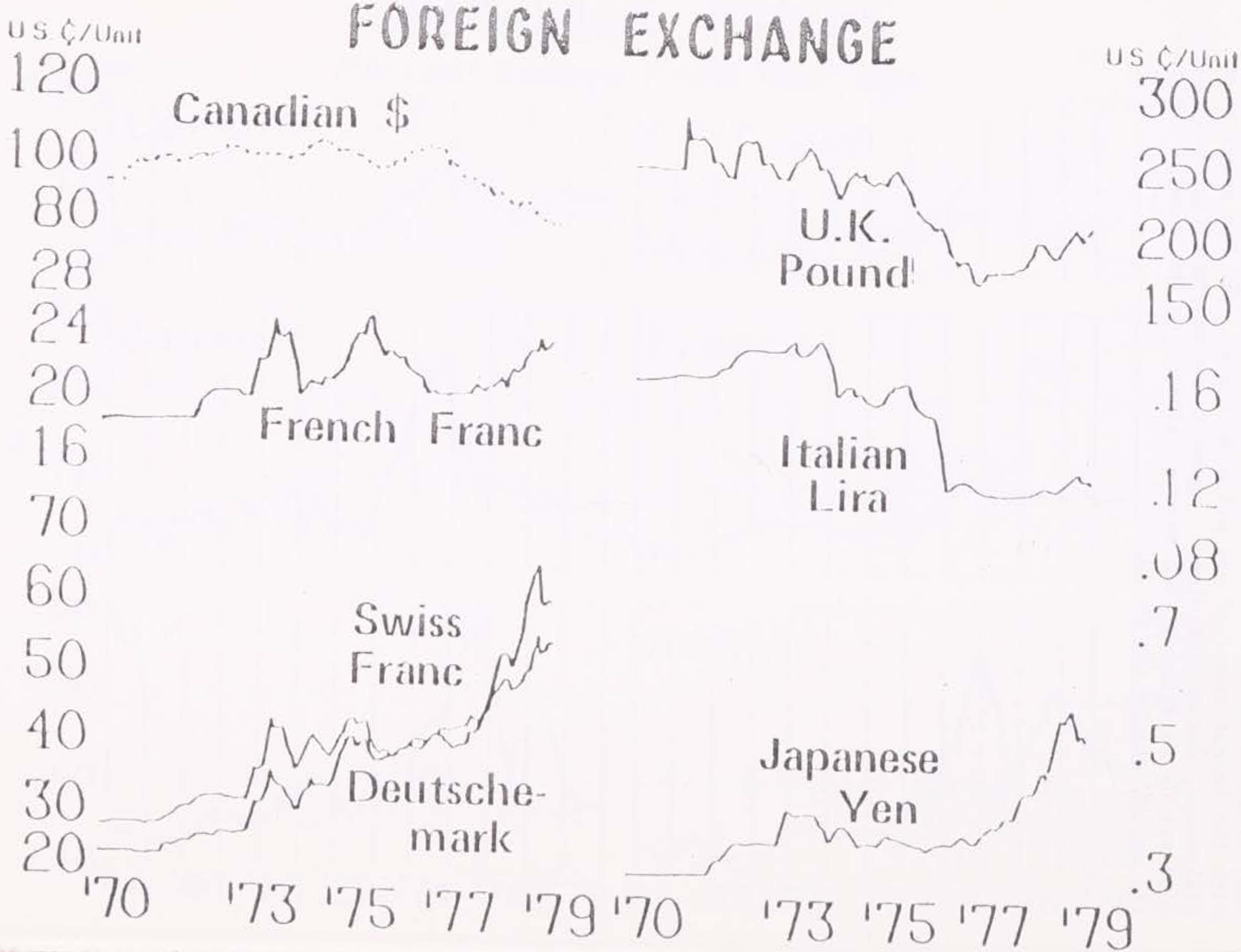
Underlying that trade imbalance, - the U.S. has had inflation which is much greater than either in Germany or Japan. Notice the Japanese inflation-rates in 1974 and 1975 exceeded those of the U.S. Through economic policy, the Japanese succeeded in bringing their inflation down to under that of the United States. Similarly for the Germans. So on the one hand you have a surplus trade-position for the Japanese and Germans against a negative for the U.S., coupled with the lower inflation-rates for the Germans and Japanese against a higher inflation-rate for the U.S.

CONSUMER PRICES



Slide 11:

As a result, we see the strengthening of the Deutschmark and the Yen, at least up until the present time. For reasons, having to do with the latest round of oil price increases, the Yen seems to be weakening. But nevertheless: lower inflation, positive trade-balances mean strong currencies, and strong relative to the reserve-currency of the world, namely the dollar.


FOREIGN EXCHANGE
U.S. ¢/Unit
120
100
80
28
24
20
16
70
60
50
40
30
20
Canadian $
French Franc
Swiss Franc
Deutsche-mark
'70 '73 '75 '77 '79
U.S. ¢/Unit
300
250
200
150
.16
.12
.08
.7
.5
.3
U.K. Pound
Italian Lira
Japanese Yen
'70 '73 '75 '77 '79

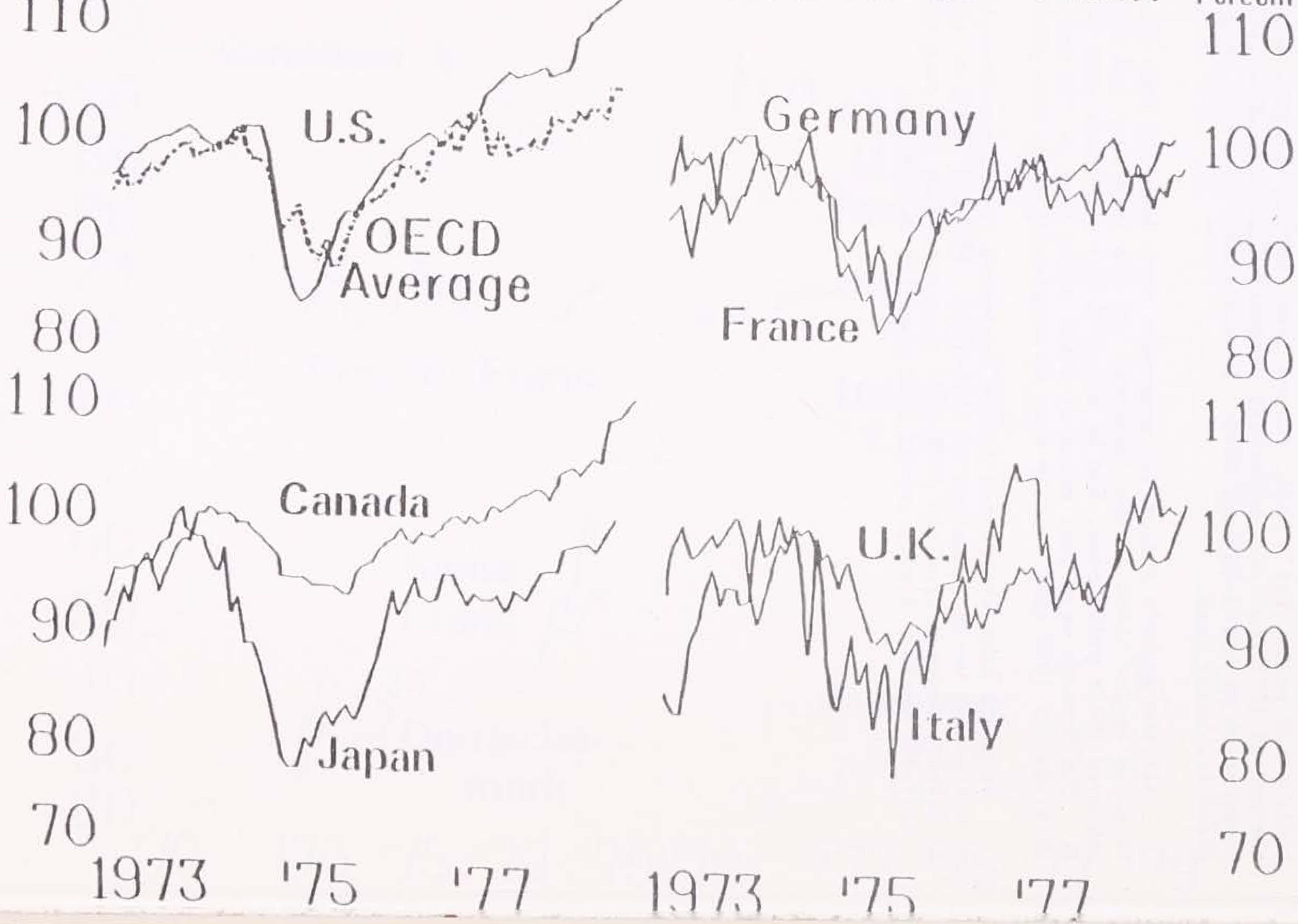
Slide 12:

Well, why did that happen? What I did here is simply to chart the industrial production-rates of the key-countries, as a percent of their prior peak. Let's look, if you like, at the United States. By the end of 1978 the U.S. industrial production was 15% above its prior peak, which occurred in late 1973. By the middle of 1979, it was 20% above its prior peak.

All the world's industrial economies went down and then started to go up again. Look at the Japanese. By end 1978 they had just about achieved their prior peak, and by mid-1979 had not moved much beyond it. The Germans were just about at their prior peak at the end of 1978; and in 1979 they've only come up marginally from that position.

It means that the United States recovered faster economically from the deep world recession of 1974-1975. Why did the U.S. sustain a sharper recovery from the 1974-1975 recession than the rest of the industrial world? I will answer that question in a moment.

INDUSTRIAL PRODUCTION – % OF PEAK



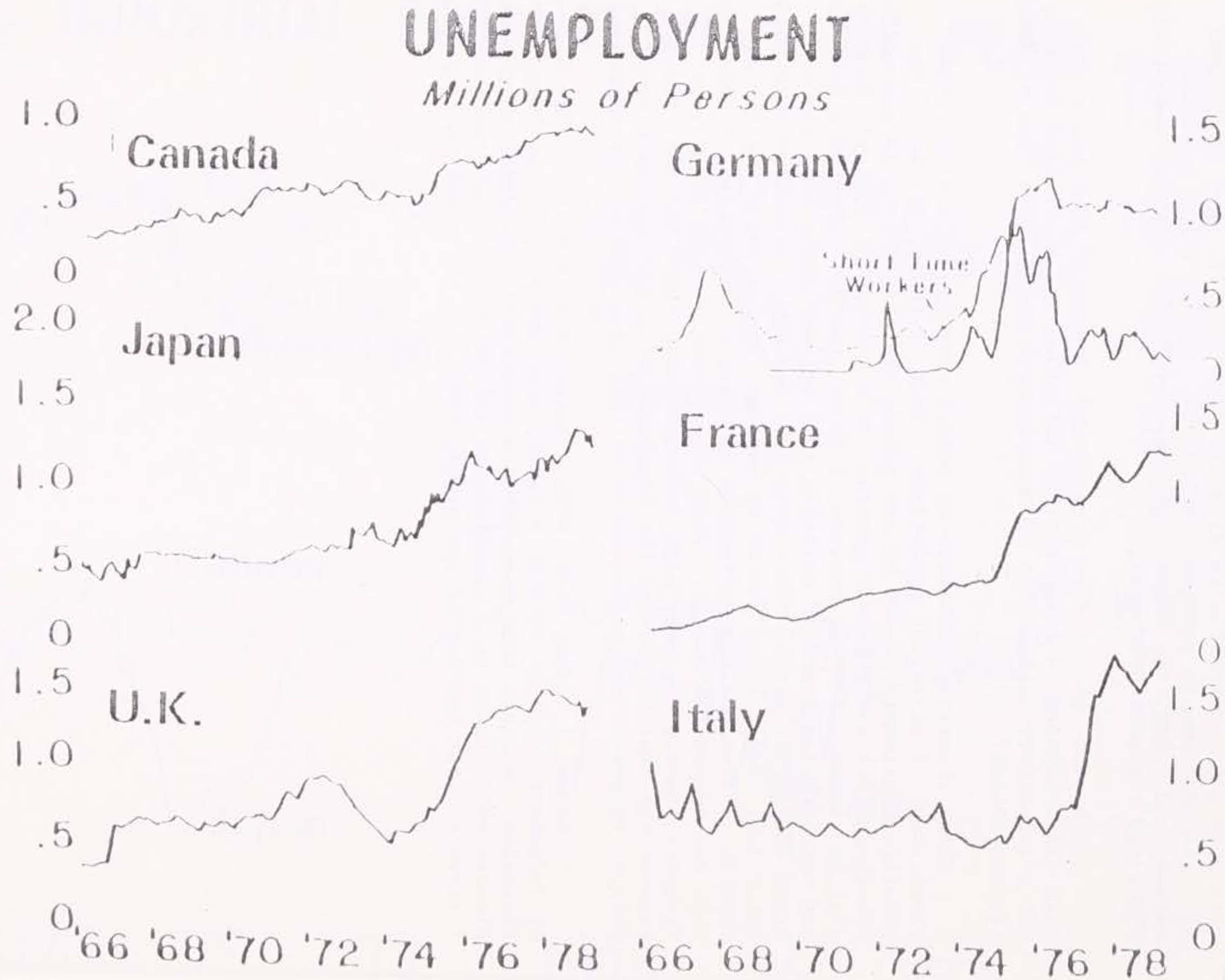
Slide 13:

Now look at relative unemployment. The United States unemployment rate came down substantially from its high in 1975, when it reached 9%. It came down to somewhere around 5%. On the other hand, for Germany and Japan, the numbers of unemployed have remained relatively higher in the post-OPEC period.

I ask you: who is more prosperous? A country that has a positive trade-balance, a lower rate of inflation and a stronger currency, but a relatively higher rate of unemployment and a lower rate of domestic production?

These countries, in terms of policy response to the oil price shock, went in different directions. That, I think, is one of the underlying elements of why we are seeing the differences in perception concerning oil and economic growth. It's government policy! We didn't work in tandem. Largely because, I think, the U.S. elected a Democrat and our peculiar brand of politics said we were going more for the bread-and-butter issue. Make more jobs and don't worry too much about inflation! Well, for a number of reasons, one of which was the disruption in Iran and the subsequent doubling of oil-prices, I think the U.S. has turned the corner. What you've been reading about very recently, namely the very high interest rates which the U.S. Federal Reserve has instituted, and the beginning of a serious tight money policy, represent the consequences of this divergent policy response.

It means, I think, that there's going to be a switch. The U.S. in my judgement, will go through a fairly deep and possibly prolonged recession. Whether this means that a Democratic president can get re-elected while there is a simultaneous inflation and high unemployment I leave to your reading of the press, since I'm not a political prophet.

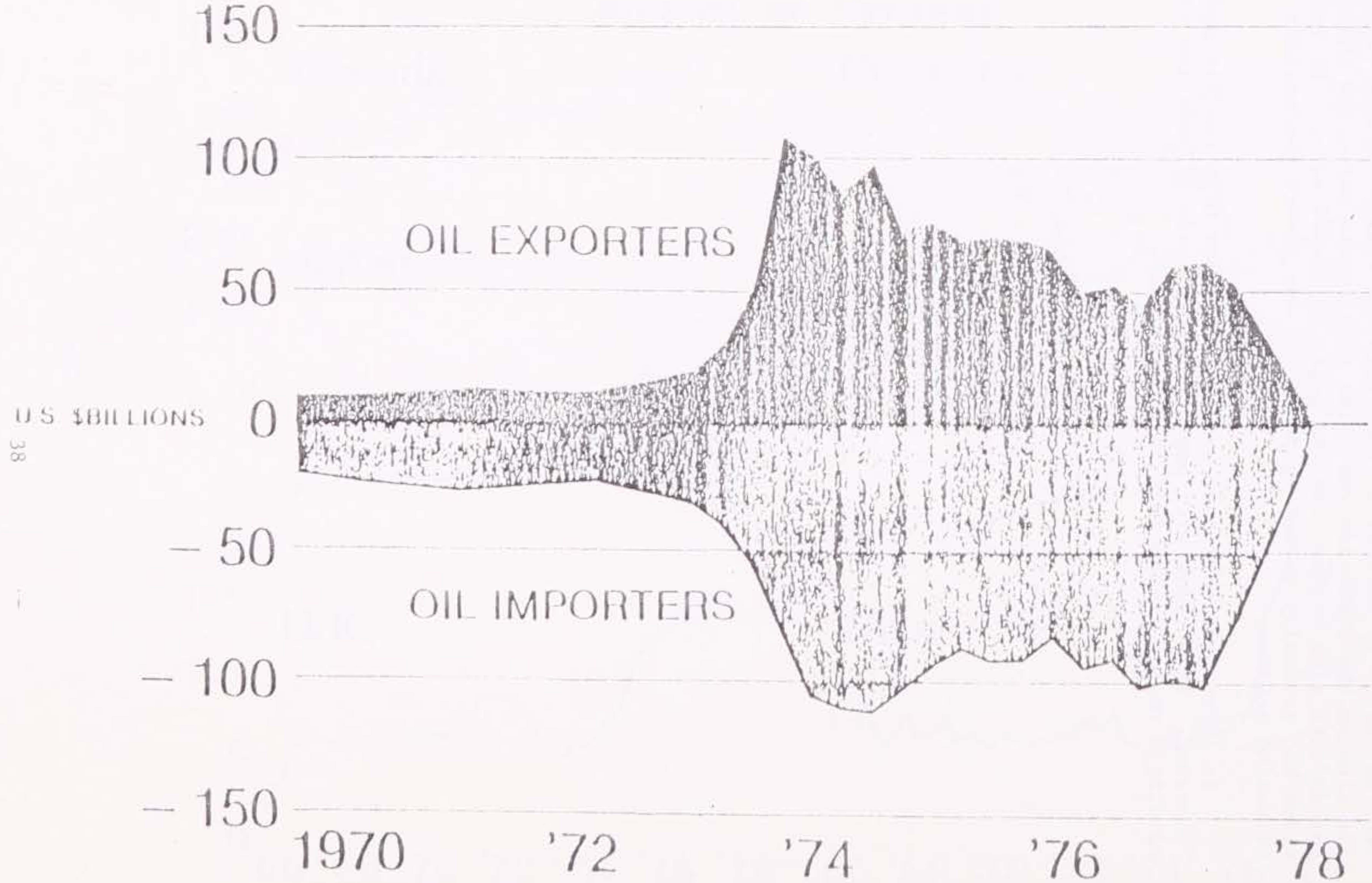

UNEMPLOYMENT
Millions of Persons
Canada
Germany
Short Time Workers
Japan
France
U.K.
Italy
1.0
.5
0
2.0
1.5
1.0
.5
0
1.5
1.0
.5
0
'66 '68 '70 '72 '74 '76 '78
'66 '68 '70 '72 '74 '76 '78
1.5
1.0
.5
1.5
0
1.5
1.0
.5
0

Slide 14:

The world was faced with a major job of recycling the huge OPEC balance-of-trade surplus and the financial consequences of the equivalent deficit. By late 1978, the world was really healing very nicely. The plus on the OPEC-side was going down toward zero, and the minus on the deficit side of the coin was going up toward zero. The terms of trade had gradually turned against OPEC and toward the western oil-consuming nations.

In 1979, that ball-game was all over, and OPEC has hit another "homerun". This chart will begin to widen again in 1979 and 1980, causing a replay of the 1974-1975 experience.

WORLD TRADE IMBALANCE



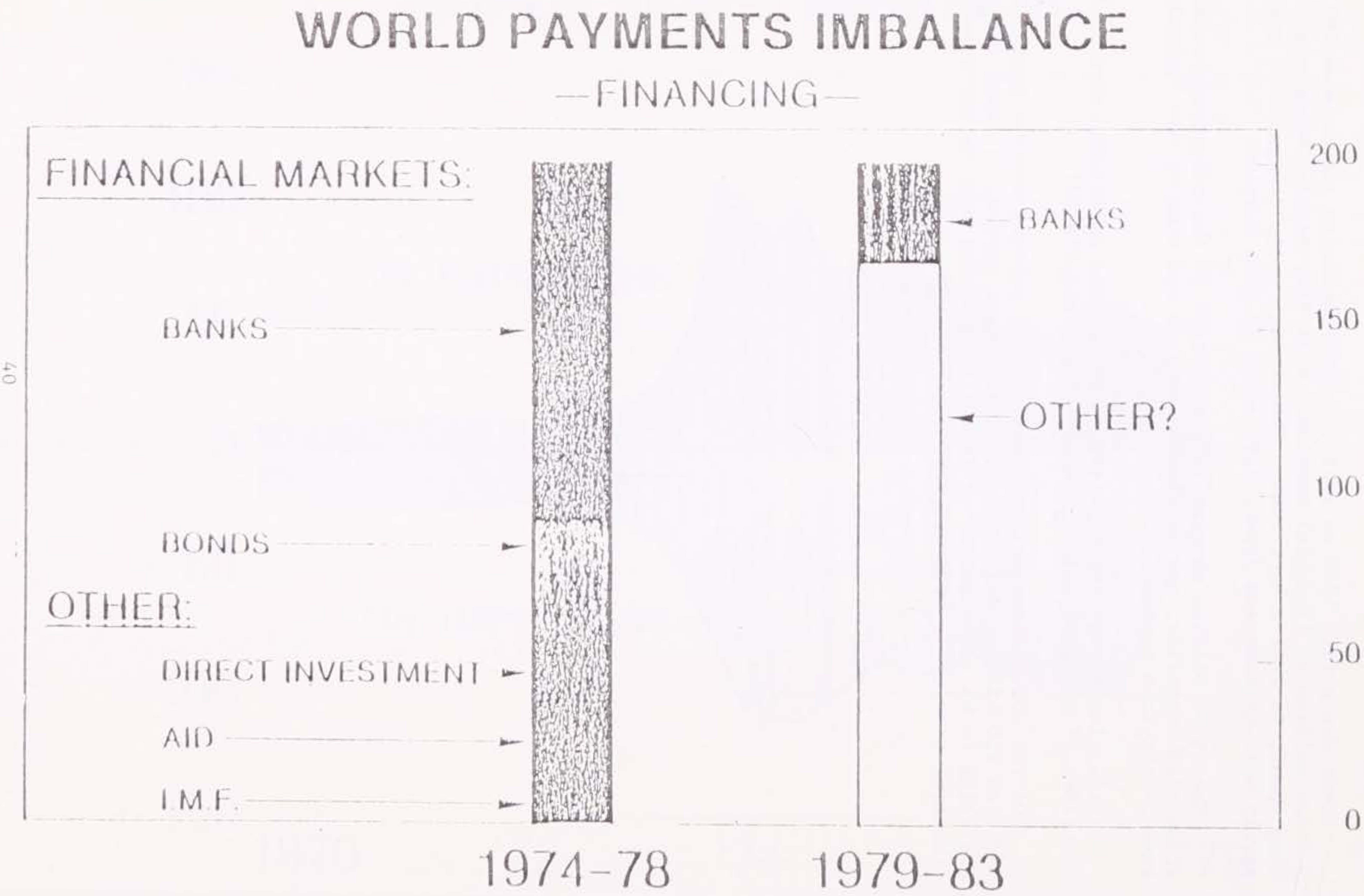
Slide 15:

Over the period 1974 to 1978 the OPEC-countries accumulated 160 billion dollars of financial surplus. What they receive minus what they spend, is what's left over. The strong currency countries, primarily West-Germany and Japan, have added to this surplus.

That $200 billion surplus is the deficit of the relatively weaker industrial countries, the developing nations and some of our "friends" east of the Iron Curtain.

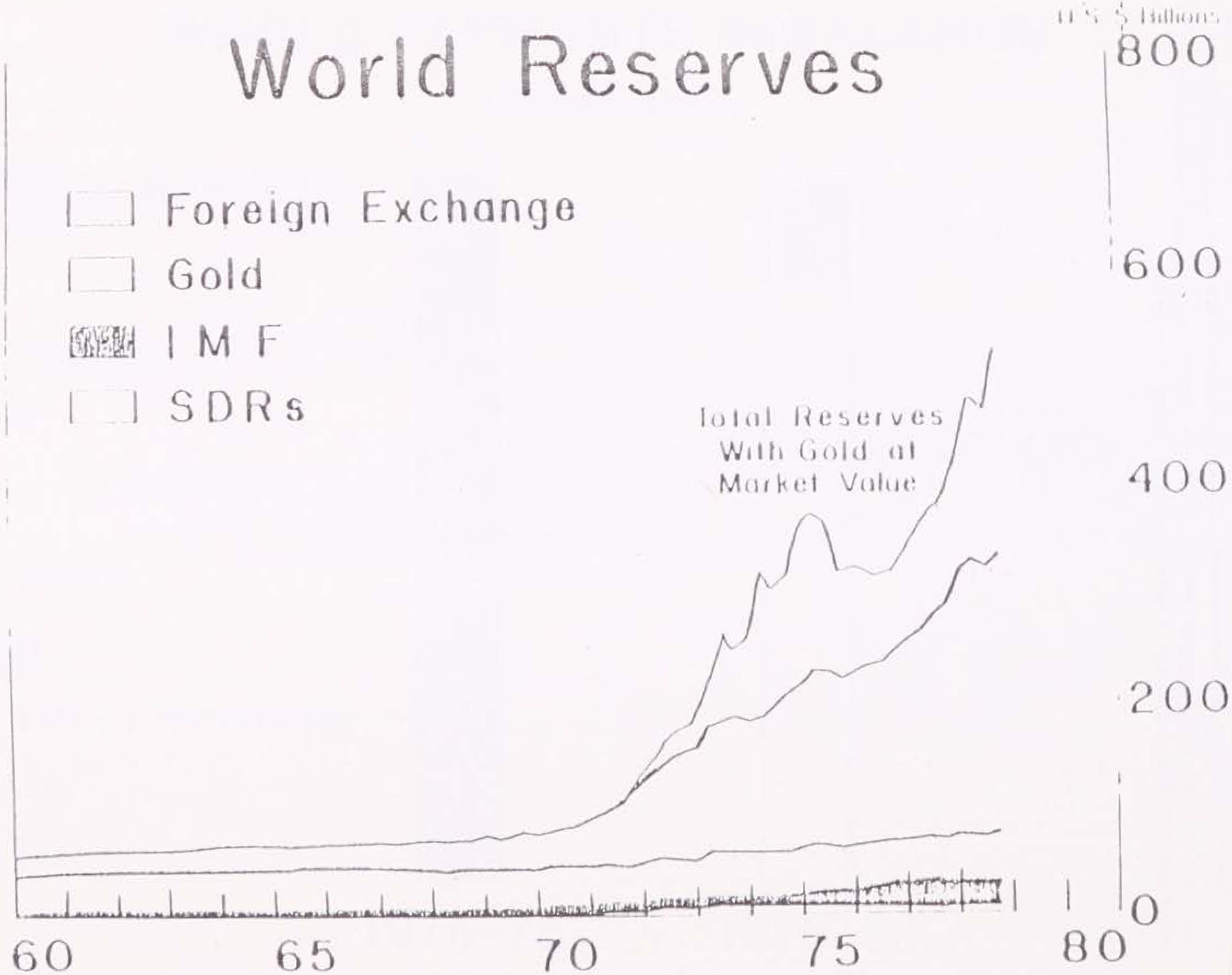
It's simply, barring statistical errors and omissions, sort of two sides of the same coin. How was this accomplished?

Of the 200 billion dollars surplus, the private western banks, recycled 110 billion dollars, over that 4 year period. I think they are going to be reluctant to do it again, and this will become a major financial problem in 1980 and beyond.


WORLD PAYMENTS IMBALANCE
—FINANCING—
FINANCIAL MARKETS:
BANKS
BONDS
OTHER:
DIRECT INVESTMENT
AID
I.M.F.
BANKS
OTHER?
200
150
100
50
0
1974-78
1979-83

Slide 16:

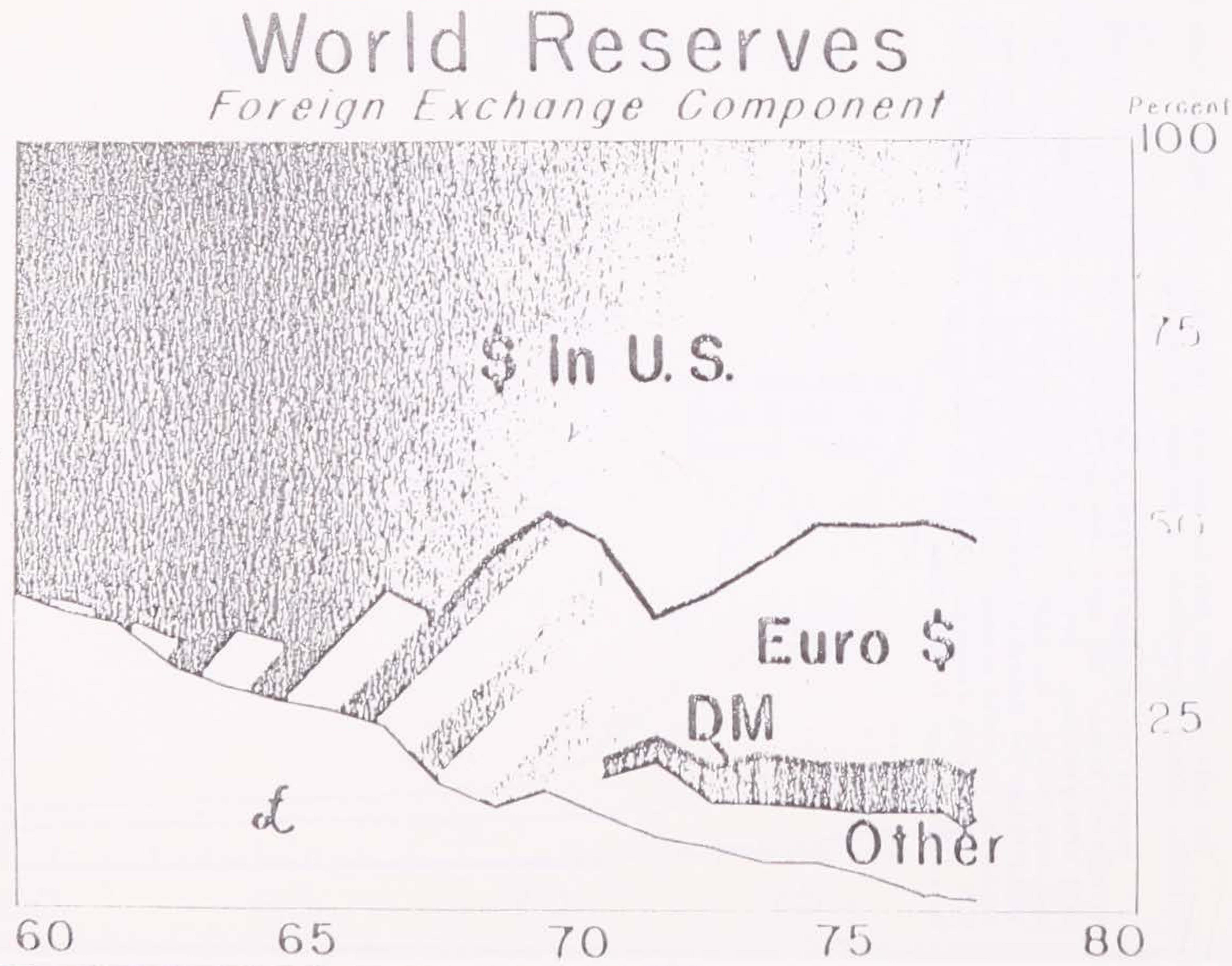
The biggest problem we have on the financial side is the strength of the dollar in international financial markets. Foreign exchange means Central Bank reserves of foreign currencies, and excluding gold represents the bulk of these Central Bank reserves.


World Reserves
Foreign Exchange
Gold
I M F
SDRs
Total Reserves With Gold at Market Value
800
600
400
200
0
60
65
70
75
80

Slide 17:

The bulk of these foreign exchange reserves, over 80%, are held in dollars, either Eurodollars or dollars in the U.S.

This is the percent of foreign exchange reserve held in dollars by Central Banks. So, when they get nervous, the financial markets will have problems. Private individuals, private speculators, companies who want credit, all know this and take action to protect themselves, aggravating the destabilization. The strength of the dollar becomes paramount to world economic and monetary stability. This is why the U.S. took strong financial action in October of 1979. I hope we will be serious about it this time.


World Reserves
Foreign Exchange Component
Percent
100
75
50
25
$ In U.S.
Euro $
DM
Other
£
60
65
70
75
80

Slide 18:

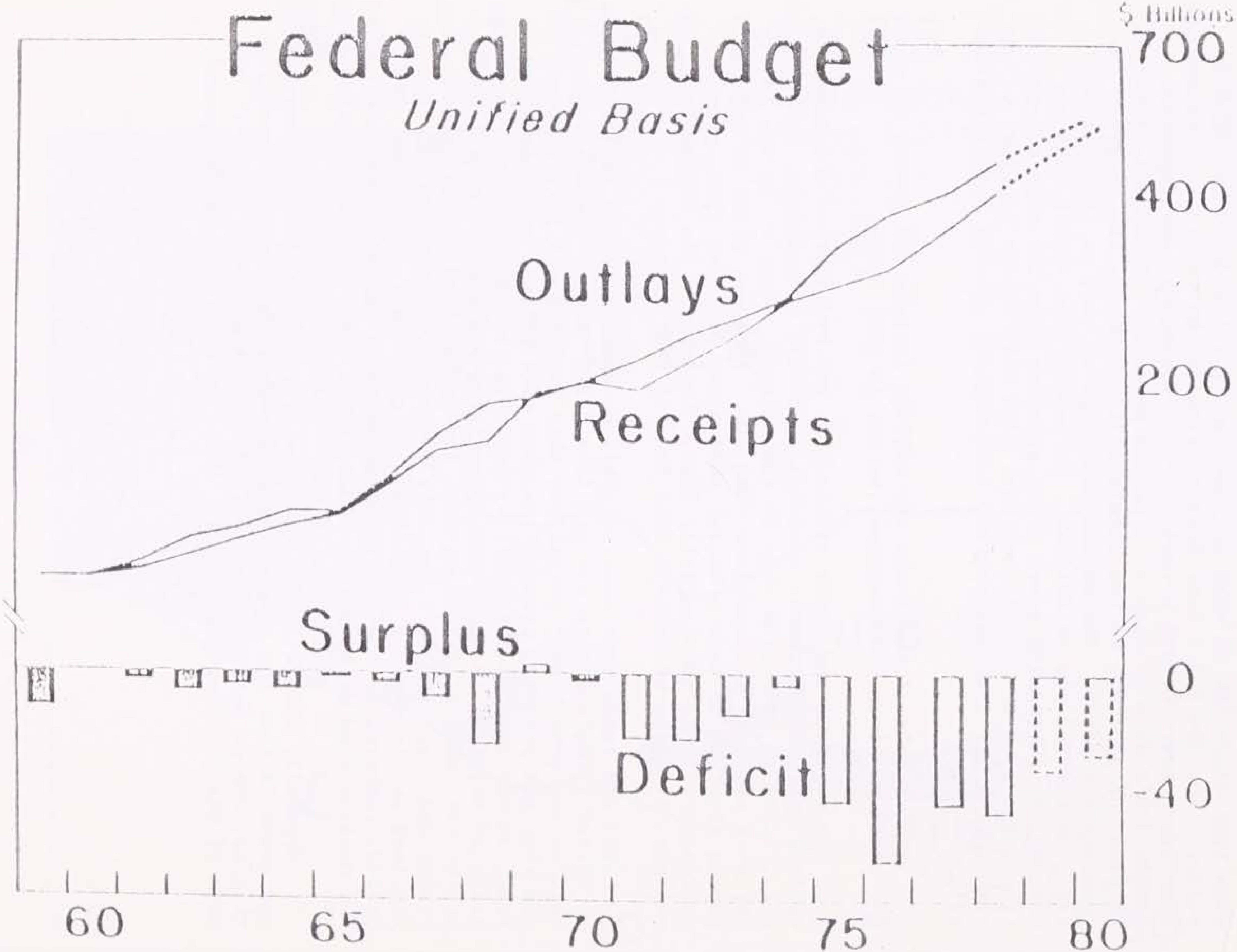
This chart shows the U.S. federal government budget deficit. I show this slide now to make an important point about domestic U.S. policy. We, the U.S., have been revving up the machine of our economy for five years. We had a choice. You, Europeans, and Japanese, really don't have as much of a choice as we do. Because half our oil is produced at home, we can regulate it. That is, the Congress can regulate the price. The second advantage we have is that the oil-trade is carried out in dollars. So rather than absorb into our economy the purchasing power drain stemming from the high oil-prices, (i.e., the loss of real income that high cost energy implies) we can pump more money into the system, domestically as well as internationally.

And as long as the Arabs are willing to take our pieces of paper for their precious hydrocarbons, we are in good shape.

The price of the paper relative to the hydrocarbon continues to decline and you Europeans, especially holders of guilders, Deutschmarks, etc., stand to gain from this in the interim. That's the way international currency transactions turn out. Because, while we may be paying about 13 dollars a barrel more since December 1978, your increases will be substantially less. Looking at the Deutschmark, for example, it would be perhaps only half of that increase.

You can trade your more valuable European currency in for dollars at better rates and then buy oil from OPEC. We, on the other hand, have to pay even higher prices for this imported oil but, I submit to you that our printing presses can work much faster, or at least as fast, as the Saudi-Arabian oil wells. Now this is not a very healthy state of affairs, as you might appreciate, and I think that's again one of the underlying lessons that are coming home to the United States and hopefully we'll be able to move to restrict this. But if you look at the massive deficit in the seventies, in the post-OPEC period, compared to the sixties when we had a few deficits, but not of the massive kind we have now. That, to me, is a very important message.

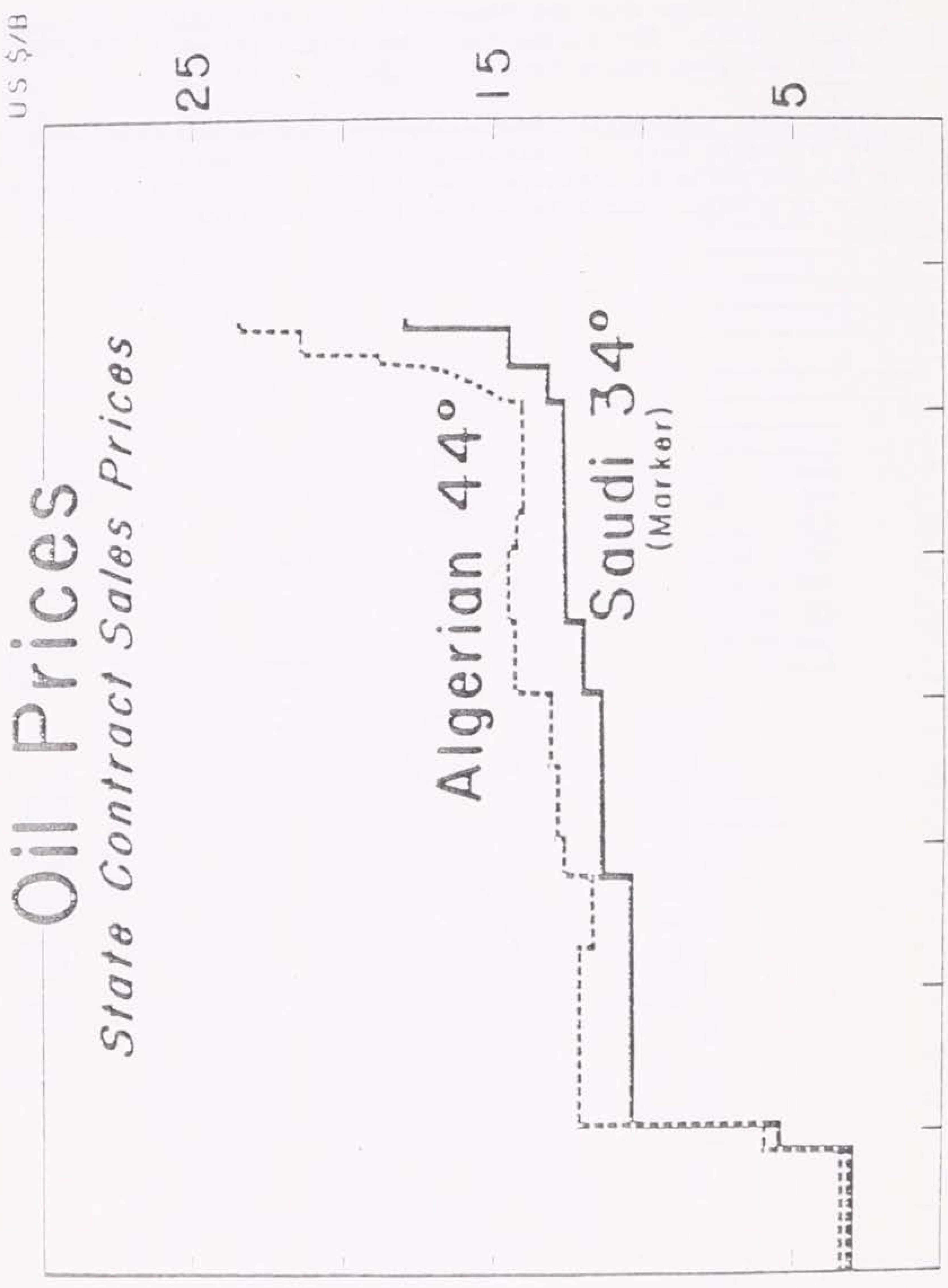
Hopefully this will not continue but, don't hold your breath. My own guess is that the discipline will have to be imposed externally; that is, one or more of these sellers of oil will one day say: No more of the printing-press game. We'll keep our oil in the ground.


Federal Budget
Unified Basis
$ Billions
700
400
200
0
-40
Outlays
Receipts
Surplus
Deficit
60
65
70
75
80

Slide 19:

Well, we all know what has happened to the oil-prices. They're now moving up again. The Saudis have just raised prices to $24/bbl level; Libya and some others have moved now up to $30.

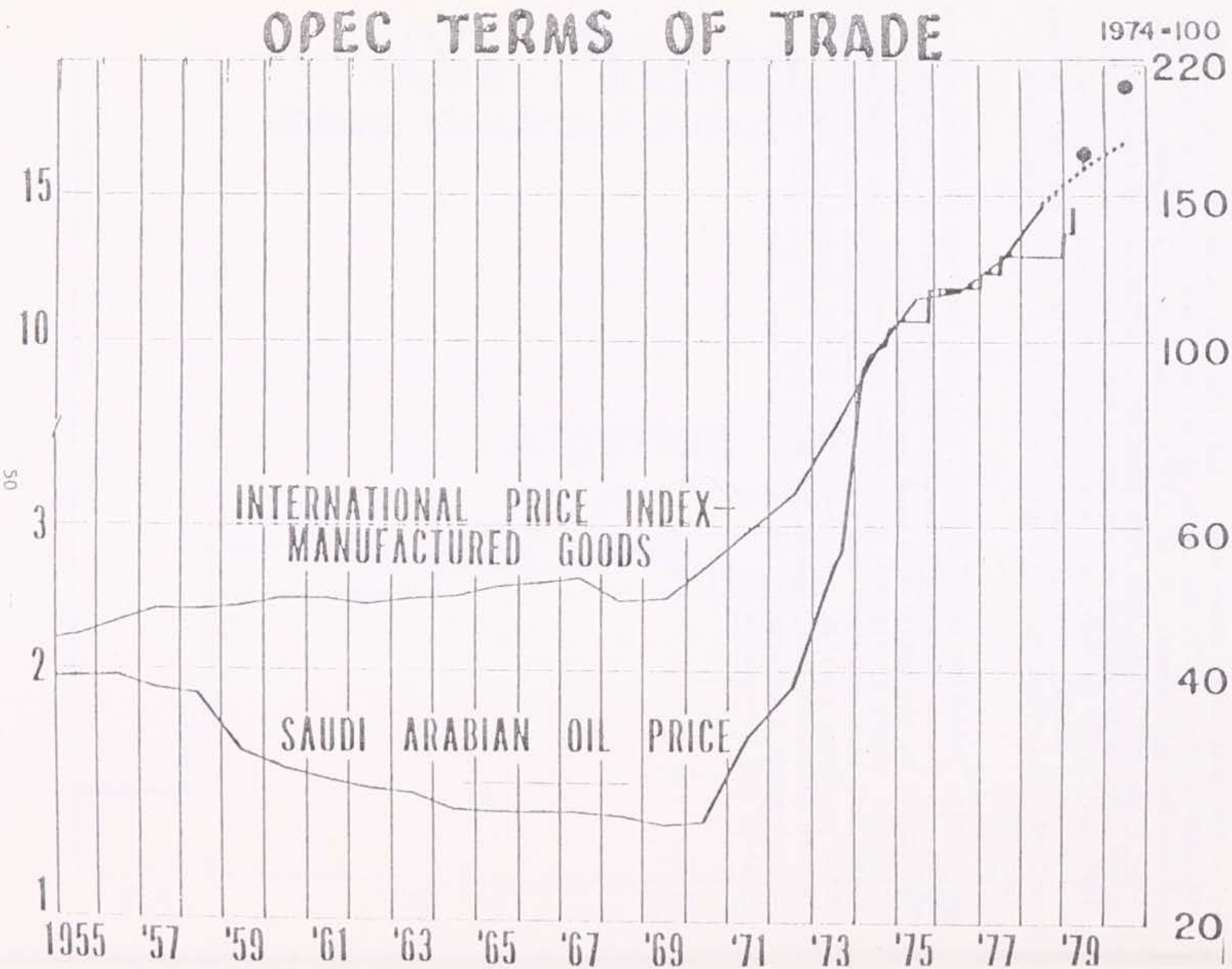
I might note that Sheik Yamani keeps telling us how Saudi Arabia is really trying to help. Considering that Saudi Arabia sells its oil now for $24.00, while it costs perhaps 24 cents to produce it, I'm not so sure it is a help. But I leave that to the vagaries of international diplomacy.


Oil Prices
State Contract Sales Prices
US $/B
25
15
5
Algerian 44°
Saudi 34°
(Marker)
73
75
77
79

Slide 20:

The next chart shows what I call the "Inflation Catch-Up Game". Throughout the 1960's, the price of oil declined relative to the cost of manufactured goods. In 1973-1974, OPEC more than caught up. From 1975-1978, oil prices grew less than world inflation, so the terms of trade once again shifted to the advantage of the oil consumers. In 1979 and likely in 1980, OPEC will run out ahead again. Western oil demand will sharply decline and new oil sources will come in. By 1981 or 1982, the situation could again revert back to the calmer days of 1976-1977.

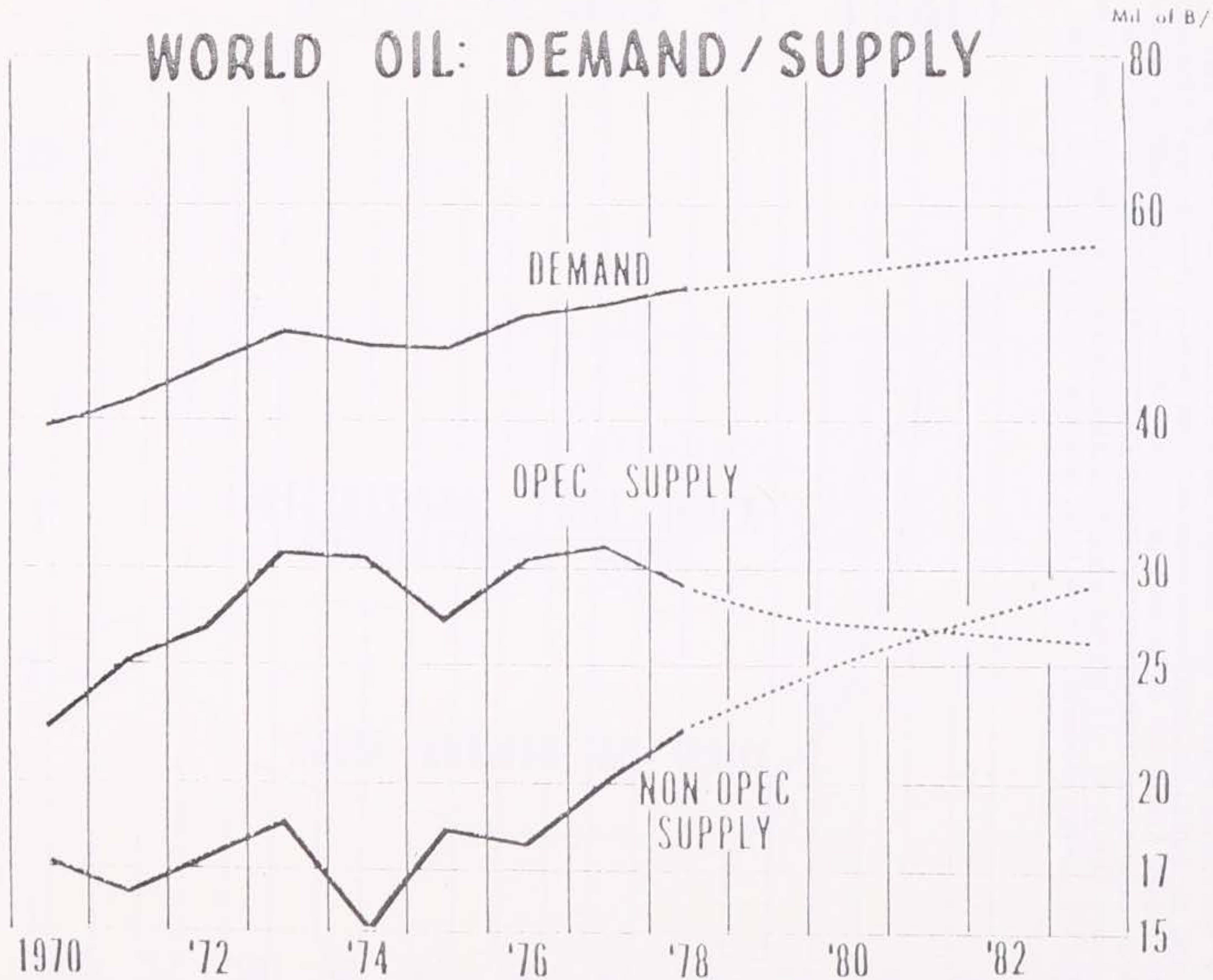
This "Inflation Catch-Up Game" has some long run damaging effects. First, it destabilizes the industrial economies, making them much more vulnerable to the swings of inflation and recession. Second, the inflation caused by high oil prices and the unwillingness to absorb these real cost increases makes for a runaway capital goods inflation which paralyzes capital investment, both in new sources of energy and in more efficient energy consuming equipment. In the final analysis, it represents a departure from open-market supply-demand pricing to politics and monopoly.


OPEC TERMS OF TRADE
1974=100
220
150
100
60
40
20
15
10
3
2
1
INTERNATIONAL PRICE INDEX-
MANUFACTURED GOODS
SAUDI ARABIAN OIL PRICE
1955
'57
'59
'61
'63
'65
'67
'69
'71
'73
'75
'77
'79

Slide 21:

Focusing on the world oil market, I believe that demand for oil in the world will grow at a slower rate than the increase in new non-OPEC oil supplies. As a result the world's need for OPEC's oil will decline in the coming years. OPEC production declines will not stem as much from an inability to produce more oil, but rather from an unwillingness to reduce prices so as to sell more oil. Whether or not reduced demand and competition from alternate energy sources will be able to stem the upward thrust of oil prices over this time remains the central question facing energy planners, economists, and the world's political leaders.

WORLD OIL: DEMAND / SUPPLY



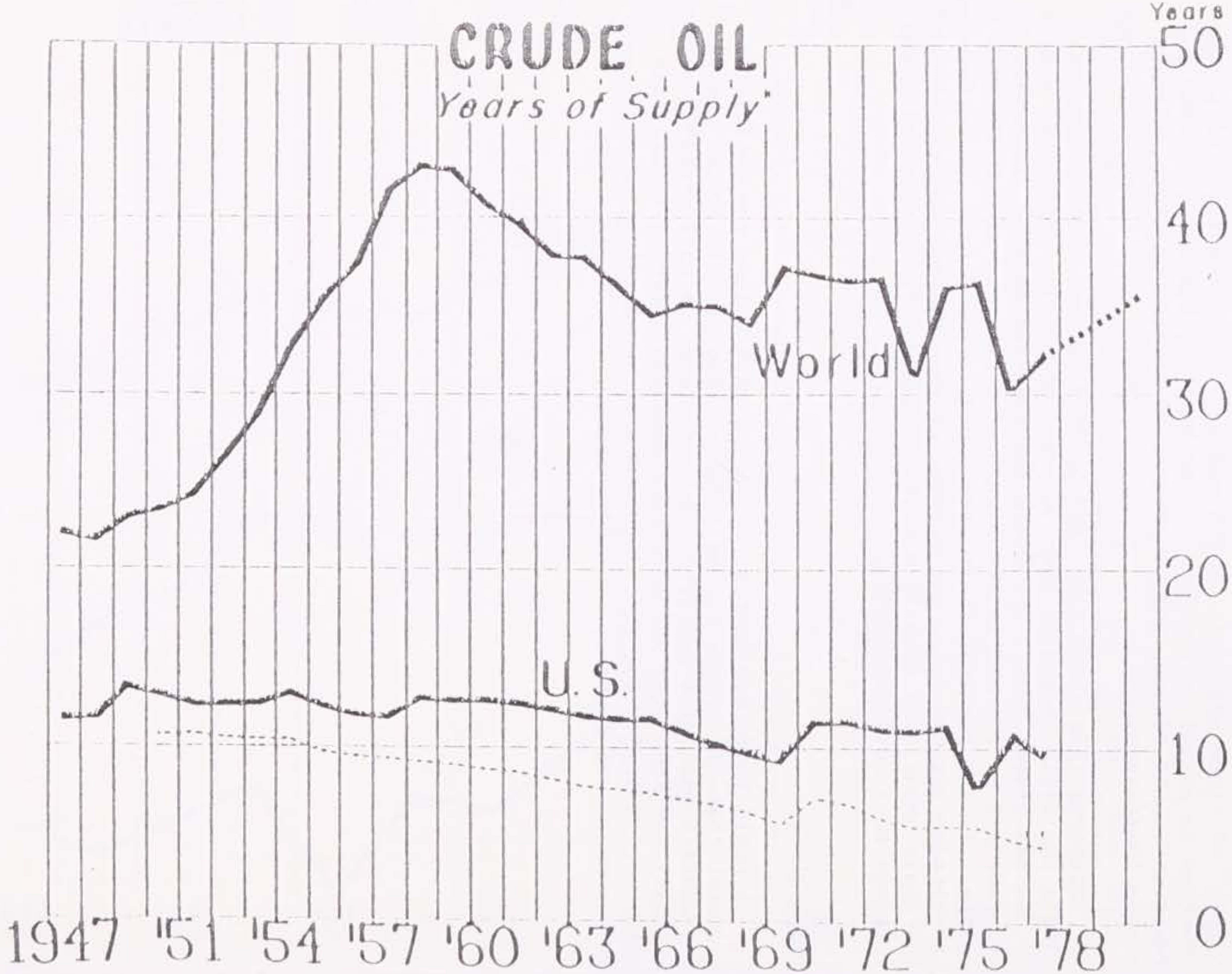
Slide 22:

I would like to leave you with one final thought concerning the potential for a world wide oil shortage. This chart shows "Years of Supply" of crude available to the market. It is the ratio of proven reserves to annual production. If we have 100 barrels of proven oil reserves in the ground, and we produce 10 barrels per year, then we have a 10 years supply.

Plotting this ratio from 1947 to 1980, we see that in the late 1980's the ratio soared to over 40 years of supply. There was a glut of oil and prices fell. The world oil industry reduced its exploration programs and by the mid-1960's brought the ratio to around 35 years of supply. It has remained there ever since. Prices have soared because of politics and monopoly, not because of any inherent market imbalance. The chart shows very clearly a stable balance between production and reserves on a world wide basis.

Conclusions

I would therefore want to leave you with a long run optimistic forecast that oil prices can be contained and the historical health of the Western economies restored. Nevertheless, we will probably suffer at least one more deep and prolonged economic downturn before this rejuvenation begins and that downturn will be caused in no small way by the continued increase in energy costs.


CRUDE OIL
Years of Supply*
Years
50
40
30
20
10
0
World
U.S.
1947 '51 '54 '57 '60 '63 '66 '69 '72 '75 '78

SECOND SESSION, Wednesday, May 21 - 10:15 a.m.

Concurrent Session B-1

RELATIONSHIPS BETWEEN REGULATED UTILITY ACCOUNTING PRINCIPLES
AND GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

CHAIRMAN: John F. Utley

SPEAKER: Morris R. Fitzgerald
Chief, Division of Audits
Federal Energy Regulatory Commission

RELATIONSHIP BETWEEN REGULATED UTILITY ACCOUNTING PRINCIPLES AND GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

Morris R. Fitzgerald
Director, Division of Audits
Office of Chief Accountant
Federal Energy Regulatory Commission

This paper sets forth remarks presented by the speaker at a panel session at the Iowa State Regulatory Conference, Ames, Iowa, on May 21, 1980. The session, moderated by John F. Utley, of the independent accounting firm of Deloitte Haskins & Sells, deals with the "Relationship between Regulated Utility Accounting Principles and Generally Accepted Accounting Principles (GAAP)." My comments are centered around the Discussion Memorandum (DM) of the Financial Accounting Standards Board (FASB) issued December 31, 1970, on Effect of Rate Regulation on Accounting for Regulated Enterprises and the written response to the DM by the Office of Chief Accountant of the Federal Energy Regulatory Commission (FERC), dated May 6, 1980. Public hearings are scheduled for May 28 and 29, 1980 in Chicago. A copy of the FERC response appears in Appendix A.

I will provide commentary on the FERC response. While comments included in the FERC response (Appendix A) represent the carefully considered views of Mr. L. H. Drennan, Jr., the FERC Chief Accountant, some views expressed herein are my own and not necessarily those of the Chief Accountant or any other FERC staff member or individual Commissioners.

FERC Accounting Regulation

The FERC response (p. 2) discusses FERC's longstanding role in having the electric and gas utilities it regulates maintain sound accounting and reporting practices to serve the needs not only of rate regulation but those of investors as well, a role which may extend beyond that of State and local regulatory bodies.

FERC Accounting and GAAP

The FERC response (p. 2-3) explains FERC's responsibilities and functions in the accounting and reporting area under Federal law. It points out that FERC uniform standards provide information generally consistent with the needs of cost based rate regulation and common measurements of the results of ratemaking processes. It points out also that FERC accounting requirements have served many years (both before and after the issuance of the Addendum to APB Opinion No. 2) to provide standards which seldom, if ever, have caused independent accountants to issue qualified opinions on conformance of financial statements to GAAP.

The view is expressed that there is no compelling need for significant changes in the accounting and reporting standards for the electric and gas companies FERC regulates, but that the FASB project may be useful in promoting better public understanding of the reasons why the application of GAAP for these industries is different than for others. The

FERC response urges that any standards adopted not differ materially from those currently prescribed by FERC, and thus result in qualified opinions and dual financial statement presentations.

The Issues

I will attempt to briefly comment on the manner in which the FERC has responded on the individual issues. Page references are to Appendix A.

ISSUE 1: Should accounting prescribed by regulatory authorities be considered in and of itself generally accepted for purposes of financial reporting by rate-regulated enterprises? (p. 3)

No. This issue by use of the words "in and of itself" can elicit no other realistic answer. Prescribed accounting consistent with sound accounting principles as supported by the ratemaking process may represent GAAP.

ISSUE 2: Does rate regulation introduce an economic dimension in some circumstances that should affect the application of generally accepted accounting principles to rate-regulated enterprises? (p. 4)

Yes. The point at which costs are recognized in setting rates on an individual cost of service basis are usually based on public policy, although there is a responsibility of ratemaking bodies to grant rates which in the long run will provide for recovery of all cost plus a reasonable compensation for the use of money invested. The economic dimension has been recognized by the Addendum to APB No. 2.

ISSUE 2.1: Should the recoverability criterion for cost deferrals be based on recovery of cost (which excludes a return on equity capital) or on recovery of cost of service (which includes a return on equity capital)? (p. 4)

No. Otherwise, the tests for an asset would be more restrictive than that for nonregulated enterprises.

ISSUE 2.2: Concerning a tariff (or its equivalent) providing for specific recovery of cost changes through revenues in a period other than the one in which cost changes occur: Does such a tariff provide an adequate basis for a utility to accrue for or defer the cost changes and charge or credit them to expense when the revenues are received? (p. 5)

Yes. This type of deferred cost is not significantly different from an unbilled accounts receivable. Ability to bill and collect rather than timing of the billing is the point on which the question turns.

ISSUE 2.3: Concerning a tariff (or its equivalent) providing an opportunity to recover changes in a cost through revenues in a subsequent period (as contrasted with the assurance in Issue 2.2): Does such a tariff provide an adequate basis for a utility to defer the cost changes and charge or credit them to expense when the subsequent period revenues are received? (p. 5)

Yes. This situation is in substance no different than that in Issue 2.2. The problem involves that of estimation based on future sales volumes. Generally predictions can be made within reasonable limits to support probability of recovery.

ISSUE 2.4: Concerning a tariff (or its equivalent) that provides for a surcharge or adjustment clause to reflect cost changes but is not considered by the regulatory agency to provide for the recovery in subsequent periods of previously incurred costs: Does such a tariff provide an adequate basis for a utility to defer the cost changes and charge or credit them to expense when revenues reflecting the surcharge or adjustment clause are received? (p. 5)

No. When Changes in cost levels are used to adjust rates automatically, the costs themselves are serving only as a proxy for recognizing changed revenue requirements for future periods, similar to the procedure generally followed in establishing base rate changes.

ISSUE 2.5: Does indication in a rate order of the treatment accorded certain revenues and expenses in determining cost of service provide an adequate basis for a utility to defer (or accelerate) the timing of revenue and expense recognition for accounting and public reporting purposes? If so, must the rate order specify the amount included? (p. 7)

Yes. The amount does not necessarily have to be specified. The word "indication" in the question is subject to differing interpretation. The FERC response presumes that indication means that the timing recognition policy or practice for a cost or revenue recognition by a regulatory authority reasonably can be established through the rate order. In practice significant regulatory policies or practice usually can be established or corroborated by reference to evidence beyond a particular rate order.

ISSUE 2.6: Does indication in a rate order of the treatment accorded certain revenues and costs in determining rate of return provide an adequate basis for a utility to defer (or accelerate) the timing of revenue and expense recognition for accounting and public financial reporting purposes? If so, must the rate order specify the amount and how it affects the rate of return (i.e., the portion applicable to it)? (p. 7)

This question without further elaboration by the Board is difficult to answer unequivocally. While under some circumstances it may be possible to trace cost recovery of an item to rate of return, FERC believes such instances would be rare.

ISSUE 2.7: Does indication in a rate order of the treatment accorded certain costs and obligations in determining rate base provide an adequate basis for determining whether they would be recognized as assets and liabilities for accounting and public financial reporting purposes? (p. 8)

The FERC response does not give a yes or no response to this question. My response would be "No". Rate base is a mathematical compilation of certain balance sheet debit and credit items and other items used by a ratemaking authority to derive an investment base to which an allowed return is applied in determining revenue requirements. The test for an asset should be recoverability, not its use in rate base calculations.

Item 2.7 requests that comments cover certain specific items. The items and the treatment in the FERC response (p. 8) follows:

Allowance for equity funds used during construction

The FERC response defers to Issue No. 7 for a response on this item.

Intercompany profit included in assets

The FERC response indicates that if recognized as recoverable through the ratemaking process it represents a valid asset. Whether it is included or excluded from investment (rate base) should not be the standard.

Deferred income taxes and leases

The FERC response, in effect, expresses the view that where a capital lease is treated the same as an operating lease for ratemaking purposes, there is no point in accounting for it in a manner that is different. In other words, if future cash flows from revenues can be deemed to occur concurrent with lease payments, there is no future sacrifice against assets shown in financial statements. Recording deferred tax provisions under flow through rate regulations is deemed unnecessary because future cash flows from revenues and payment of actual taxes can be expected to occur concurrently. The question of whether deferred taxes constitutes a liability has not been ruled on by the Board nor is is a subject for ruling in this project.

ISSUE 2.8: Does the use of a "fair-value" rate base in setting a regulated enterprise's rates provide a basis for reflecting utility plant at that value in financial statements prepared for public financial reporting purposes? (p. 8)

No. There is no need for utilities to depart from the historical cost standard in recording assets because of different rate base treatment. Rate base and allowed rate of return on rate base are simply techniques of arriving at the cost of service returns to be provided for in rates and offer no basis for restating recoverable asset values.

ISSUE 2.9: Does an enterprise's request for rate-making treatment of an item or revenue or expense provide adequate evidence to defer (or accelerate) the timing of revenue and expense recognition for public financial reporting purposes when the rates are set on the basis of a negotiated settlement agreement in which the disposition of the item of revenue or expense is not stated?

ISSUE 2.10: If an accounting order or directive covering an unusual event or transaction that arises when there is no rate proceeding indicates it will be followed in future rate proceedings, does this provide an additional economic dimension that should affect the application of generally accepted accounting principles?

ISSUE 2.11: Concerning an accounting order or directive that covers an unusual event or transaction that arises when there is no rate proceeding but that does not indicate the rate treatment to be followed in future rate proceedings: Does this provide an additional economic dimension that should affect the application of generally accepted accounting principles when:

1. The prescribed treatment is similar to that followed by the regulatory agency for rate-making purposes involving the same or other enterprise?

2. There is no rate-making precedent in the same jurisdiction for the matter involved?

3. The prescribed accounting differs from that previously followed by the same agency for rate-making purposes?

ISSUE 2.12: In the absence of an accounting order or directive, does the fact that similar items have received a certain rate treatment in the past provide an additional economic dimension affecting the application of generally accepted accounting principles? Does it make a difference whether the enterprise requested an order or directive but the agency refused to issue one?

ISSUE 2.13: In the absence of both an accounting order and a rate-making precedent, are there situations in which a legal opinion is sufficient evidence to affect the application of generally accepted accounting principles?

The FERC comments related to Issues 2.9 through 2.13 are set forth in the discussion appearing on p. 6 and 7 of the response. The questions seek comments on the type of support needed to support a different application of GAAP to regulated enterprises. The FERC response emphasizes the need for judgment and that the absence or presence of one or more types of support would not be conclusive as to assurances provided through the rate-making process. The FERC response points out that there may be circumstances where adherence to uniform accounting procedures is more important than conformance with every unique regulatory practice of individual regulatory bodies.

ISSUES 2.14 through 2.18

These appear under Chapters 7 and 8 of the DM and relate to regulated activities with which the FERC staff is unfamiliar. Accordingly no response was provided for such issues.

ISSUE 3: Should any pronouncement issued by the Board identify specific industries affected? (p. 9)

No. Standards should be established which will limit the application to any industry or segment where appropriate. In view of this answer no answer to 3.1 concerning particular industries was supplied.

ISSUE 4: Should the effects of rate-making transactions applicable to prior periods be accounted for as prior-period adjustments? If so, should the matter be included in a pronouncement coming out of this project, or should it be covered in an amendment to or interpretation of FASB Statement No. 16, Prior Period Adjustments? (p. 9)

Yes. Refunds are a proper item for prior period adjustments. The matter should be dealt with in this project and also through amendment of Statement 16.

ISSUE 5: How should regulated enterprises give effect to changes in accounting principles when:

1. An FASB Statement requires retroactive application or a cumulative adjustment, but the change will be applied prospectively for rate-making purposes?

2. Following a change prescribed by the FASB, rates that had been established on a basis that reflected the prior principle continue in effect? (p. 10)

Accounting in either case should be consistent with rate-making.

ISSUE 6: Should any pronouncement dealing with the impact of rate regulation specify mandatory application? (p. 10)

Yes. Creditability of the pronouncement requires this.

ISSUE 7: Does the rate-making process support reporting the contra credit to any capitalized cost of equity funds used in construction as current income?

Yes. Well established regulatory procedures establish the recoverability of this item over the useful life of the asset. Cost of equity is a real item of construction cost and measurability is no problem under the regulated utility environment.

ISSUE 8: Should the financial statements of a regulated enterprise disclose the effect of differences between those statements and what they would be if the enterprise were nonregulated? Should the same standards apply to both the balance sheet and the income statement? (p. 11)

No. Financial statements should not disclose the differences based on a hypothetical nonregulated activity. Responses to Issue 8.1, 8.2, and 8.3 were not provided since they deal with the manner of disclosure which the FERC response asserts would be inappropriate. However, the FERC response indicates the view that notes to financial statements should disclose significant accounting and ratemaking policies.

ISSUE 9: What disclosures of rate-making treatment should be made if it is concluded that such treatment should not affect the application of generally accepted accounting principles? (p. 11 & 12)

The FERC response indicates that under such circumstances financial statements would be misleading and any attempts to remedy the defects would only tend to confuse readers.

ISSUE 10: What other information, if any, should be disclosed about rate making? Where in financial reporting should that additional information be disclosed? (p. 12)

The FERC response is that as stated for Issue 8.3. That is, accounting and ratemaking disclosures through through notes.

ISSUE 11: Should any new standards on accounting for the impact of rate regulation be applied:

1. Retroactively be restating all prior periods presented?
2. Retroactively by including a cumulative adjustment in the current period?
3. Prospectively? (p. 12 & 13)

The FERC response recommends prospectively.

Could the project tend to weaken the financial strength of public utilities?

Some respondents to the DM have expressed the view that if the Board should determine that there should be no different application of GAAP to public utility from that for nonregulated enterprises, investor reaction to the less favorable financial presentations would impair the ability of public utilities to obtain financing necessary to carry out their public responsibility of assuring continuous adequate service. While I share this concern I also have a concern that is less commented about. That concern is that the project in affirming the need for different application of GAAP will do so with standards so broad that they will encourage changes in ratemaking processes that will tend to weaken the financial strength of public utilities, particularly by lengthening the time between the recognition of earnings and their realization in cash through revenues charged customers.

Certainly the financial community in risk evaluation must consider the length of time required to convert reported earnings and related assets to cash. The longer recovery is deferred the less confidence in recovery and a greater risk is perceived. Whether assets are in the nature of investment in productive facilities or simply those created as the result of ratemaking actions are also a factor to be considered by investors.

In the past decade there has been a growing concern by the financial community stemming at least in part to the large percentage of reported earnings of public utilities embodied in AFUDC credits to the income statement, a credit not accompanied by concurrent cash flow. Cash for this item is recoverable through depreciation expense during plant service life which on the average may extend thirty to forty years. I have no quarrel with accounting standards which allow both the debt and equity component of AFUDC as a valid cost of a productive facility. These components have no less of an opportunity for recovery than material labor and overhead costs capitalized as part of the cost of a facility which can operate to produce a service of economic value. But a point here is the perception of the investor for the period required to translate earnings into cash.

However, an asset in the nature of a deferred loss which has its genesis only through the operation of the ratemaking process in my opinion should be viewed quite differently from viable in service physical assets. Recently I have seen an emerging practice in a rate jurisdiction which would call for carrying charges to be added on top of recognized property losses until such time as the regulatory body can investigate the correctness of the losses including management prudence and then grant rates which will either reject or affirm the recoverability of the losses plus the carrying charges that have been previously reported in earnings. Further in some juristictions there is an emerging practice of removing plant from rate base either in whole or partially on the basis that is is not serving the rate payer to its full capacity with instructions to the utility to enhance the book value of the asset with carrying charges or AFUDC. Another practice emerging is to string out the recovery in rates of deferred property losses over periods of twenty to thirty years with accounting instructions to hold the deferral as an asset over the recovery period. There is a valid regulatory need to provide for recovery of property losses prospectively through rates because rates cannot be set in anticipation of such losses However, any process that does not provide for disposition of losses, which are not providing any useful service, within a relatively short period of time is simply increasing the risk of nonrecovery and of continuously carrying loss type "assets" indefinitely.

In administering uniform systems of accounts FERC has exercised control over the accounting so as to provide restraints over such unusual type regulatory practices. This has been done by controlling the period of amortization of property losses and not providing for inclusion of carrying charges in the accounts, except, of course, in the case of construction where AFUDC is authorized.

In short, I would hope that the Board in announcing any standards for different application of GAAP for public utilities would do so in a way that will not encourage ratemaking practices which either expand deferral of costs or extend their recovery over lengthy periods. Encouraging such practices, in my view, in the long run would not be in the best interest of the utility, its investors and the public. Thank you.

APPENDIX A

Federal Energy Regulatory Commission
Washington 20426

In Reply refer to:

May 6, 1980

Director of Research and Technical Activities
Financial Accounting Standards Board
Stamford, Connecticut 06905

Re: File Reference 1043-013P

Dear Sir:

This is the response of the Office of Chief Accountant, Federal Energy Regulatory Commission (FERC), to the FASB discussion memorandum on the Effect of Rate Regulation on Accounting for Regulated Enterprises, dated December 31, 1979.

Before providing our comments on the individual issues, we are presenting for the Board's information a discussion of the long-standing role of FERC, formerly the Federal Power Commission (FPC), in promoting sound accounting and reporting.

The Office of Chief Accountant is the staff organization having primary responsibility for administering the Commission's financial accounting and reporting programs carried out under the Federal Power Act (electric utilities), the Natural Gas Act (natural gas transmission companies), and the Interstate Commerce Act (oil pipeline carriers). These programs are among the various FERC regulatory activities which include setting rates for wholesale (sales for resale) sales of electric utilities and natural gas transmission companies engaged in interstate commerce and tariff rates for interstate oil pipeline carriers. Wholesale rates of electric utilities and natural gas transmission companies have for years been set on an individual cost of service basis using an original cost rate base. Policies of FERC for rate regulation of oil pipeline carriers are being developed. Accounting and reporting regulations for oil pipelines adopted by ICC continue in effect but may require future revision in accord with FERC oil pipeline rate regulatory policies.

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FERC Accounting Regulation

The role of FERC in regulating accounting and reporting by electric utilities stems from provisions of Part III of the Federal Power Act adopted concurrently with the Public Utilities Holding Company Act of 1935. The provisions are a part of a series of laws enacted by the Congress following the Depression in the early 30's and the disclosure by the Federal Trade Commission of unsound accounting practices followed by the electric industry.

The Natural Gas Act, enacted in 1938, included provisions for accounting and reporting similar to those set forth in Part III of the Federal Power Act. Effective January 1, 1937, the FPC first adopted a Uniform System of Accounts for electric utilities and, effective January 1, 1940 a seperate, although similar system was adopted for natural gas companies. The systems were formulated to (1) assure sound uniform accounting and financial reporting to security holders, and (2) to provide useful accounting information consistent with ratemaking techniques generally prevalent in the industries. The systems have been updated from time to time to reflect new accounting and ratemaking developments. At the time the accounting systems were initiated, various state regulatory agencies had adopted diverse accounting requirements. The role of such state agencies was focused primarily on the public served by a regulated company rather than its security holders. Since then, our Uniform Systems have been adopted by many state commissions, and have been incorporated, by reference, in bond indentures and cost of service tariffs. The Uniform Systems are founded on sound accounting concepts and embody accounting principles generally similar to those applicable to other industries. However, the Uniform Systems also include special provisions to reflect cost of service ratemaking treatment for some items. Thus since 1937 the FPC and now the FERC have served as a promoter of sound accounting standards and practices.

FERC Accounting and Generally Accepted Accounting Principles

We believe our Uniform System of Accounts continues to be an appropriate means of accounting regulation. Our uniform standards provide for financial information generally consistent with the needs of cost based rate regulation and common measurements of the results of the ratemaking process.

Prior to and after the adoption of the Addendum to APB Opinion No.2, the accounting requirements for electric utilities and natural gas companies administered by FERC and its predecessor, the Federal Power Commission (FPC), have not imposed a need for independent accounts to qualify opinions as to the conformance of the financial statements to generally accepted accounting principles. Insofar as those industries are concerned, we see no compelling need for significant changes in the accounting and reporting standards, although the present project may be useful in promoting a better public understanding of the reasons why accounting by these industries is not identical with that of nonregulated industries. We urge that the project not result in the adoption of accounting standards for companies regulated by FERC that vary materially with those currently prescribed by FERC. We hope that any standards adopted would not result in qualified opinions of independent accountants and dual presentation of financial statements. Such a situation would detract from the credibility of the statements and otherwise operate to the detriment of the industries, their investors, and the public they serve.

Issue 1: Should accounting prescribed by regulatory authorities be considered in and of itself generally accepted for purposes of financial reporting by rate-regulated enterprises?

While we believe that the accounting prescribed by FERC in its Uniform Systems of Accounts is conceptually sound, appropriately reflects the economic impact of regulation, and is, in fact, generally accepted, our answer to the question is "no!" Obviously, the term "generally accepted" would become meaningless if it encompassed any and all accounting prescribed by regulatory authorities. There are no assurances that the accounting prescribed by regulatory authorities will always be based on conceptually sound accounting principles. While some protective procedures usually exist, there are no guarantees that wholly unsupportable accounting will not be prescribed.

Issue 1.1: If prescribed accounting should be considered "generally accepted," are there any limiting factors?

Not applicable. See comment to Issue 1.

Issue 2: Does rate regulation introduce an economic dimension in some circumstances that should affect the application of generally accepted accounting principles to rate-regulated enterprises?

Yes. We believe that the Addendum currently recognizes this economic dimension which is primarily one of timing. We believe that proper matching generally cannot be achieved unless cost and revenues are accounted for in the same manner as the costs and revenues are treated in establishing the cost of service of utilities.

Issue 2.1: Should the recoverability criterion for cost deferrals be based on recovery of cost (which excludes a return on equity capital) or on recovery of cost of service (which includes a return on equity capital?) (Respondents are asked to explain the basis for their responses.)

The recoverability criteria should be based on recovery of cost. We believe that a deferred cost which is likely to be recovered meets the essential characteristics of an asset, as described in the Exposure Draft (Revised) on Elements of Financial Statements of Business Enterprises, in that:

(a) a probable future benefit exists

(b) The enterprise can obtain the benefit

(c) The transaction or event giving rise to the enterprises' claim to or control of the benefit has already occurred.

We believe that to require assets of public utilities to meet further tests would go beyond that required of non-regulated firms in that there are no general requirements that assets produce profits (return).

Issue 2.2: Concerning a tariff (or its equivalent) providing for specific recovery of cost changes through revenues in a period other than the one in which cost changes occur: Does such a tariff provide an adequate basis for a utility to accrue for or defer the cost changes and charge or credit them to expense when the revenues are received?

Yes. Consistent with our comment on Issue 2.1, when a valid asset is involved, such as costs deferred under purchased gas adjustment clauses and electric generation fuel adjustment clauses that specifically provide for recovery in a future period, we believe that a probable future benefit is present whether a legally collectible receivable is present or not. In that respect, we do not believe a deferred cost differs from a tangible asset when the opportunity for cost recovery is present. "Guaranteed" recovery of a cost should not be a prerequisite to its recognition as an asset.

Issue 2.3: Concerning a tariff (or its equivalent) providing an opportunity to recover changes in a cost through revenues in a subsequent period (as contrasted with the assurance in Issue 2.2): Does such a tariff provide an adequate basis for a utility to defer the cost changes and charge or credit them to expense when the subsequent period revenues are received?

Yes. As stated in our response to Issue 2.2, we believe that "guaranteed" recovery of a particular cost should not be a prerequisite to its deferral when a probable future benefit is present.

Issue 2.4: Concerning a tariff (or its equivalent) that provides for a surcharge or adjustment clause to reflect cost changes but is not considered by the regulatory agency to provide for the recovery in subsequent periods of previously incurred costs: Does such a tariff provide an adequate basis for a utility to defer the cost changes and charge or credit them to expense when revenues reflecting the surcharge or adjustment clause are received?

No. In this instance the regulatory agency is merely using cost levels in one period as a proxy for expected cost levels in a subsequent period. This ratemaking technique does not constitute justification for cost deferrals.

Issue 2.5 - Issue 2.7; Issue 2.9 - Issue 2.13: We have some general comments on these issues and have additional comments on some of the specific issues.

We believe that it is not necessary nor practical to attempt to provide specific guidelines for determining whether certain costs and obligations should be recognized as assets or liabilities or whether a transaction which would result in the recording of an expense or revenue by a nonregulated company should be deferred or accelerated by a regulatory company. Generally, we believe that if a rate order clearly specifies the treatment accorded costs and obligations in determining rate base or accorded revenues or expenses in determining cost of service (Issue 2.5), the accounting and public reporting should reflect the provisions of the rate order so that the financial results of the utility will be

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fairly stated. However, there may be circumstances where adherence to Uniform Accounting procedures is more important than conformance with every unique regulatory practice of individual regulatory bodies.

As the Discussion Memorandum points out, it is not always clear in a rate proceeding the specific treatment afforded revenues or expenses in determining cost of service (Issue 2.9). Also, absent a rate directive, there may not be adequate assurance when an accounting order or directive is received (Issues 2.10 and 2.11) that costs and obligations or revenues and expenses will be treated in a rate proceeding in the same manner as approved by the order or directive and, finally, there is even less assurance when neither a rate nor accounting order has been received by the utility (Issues 2.12 and 2.13).

It is well established in public utility rate regulation that certain costs that would be expensed by a nonregulated company are permitted to be amortized and recovered in the rate levels of public utilities. Amortization of extraordinary property losses, amortization of fuel costs, and amortization of research and development are some examples. In those situations when assurance has not been received in the form of a rate order specifying the treatment accorded certain revenues or expenses in determining cost of service, and the cost is not the nature that the ratemaking treatment is well established, we believe that the utility and the reviewing public accountants must look to precedent and the prevailing regulatory climate. In other words, judgment, depending on the circumstances, must be applied in determining whether expenses and revenues should be deferred or accelerated or certain costs and obligations should be recognized as assets or liabilities. It is possible that precedents may be changed and the regulatory climate may deteriorate. However, there is no evidence to indicate that such possibilities present a real threat to recovery of costs previously deferred under the existing ratemaking policies.

Issue 2.5: Does indication in a rate order of the treatment accorded certain revenues and expenses in determining cost of service provide an adequate basis for a utilitiy to defer (or accelerate) the timing of revenue and expense recognition for accounting and public reporting purposes? If so, must the rate order specify the amount indicated?

Yes. As indicated in our general comments on these issues, we believe that indication in a rate order of the treatment accorded certain revenues and expenses in determining cost of service usually provides an adequate basis for a utility to defer (or accelerate) the timing of revenues and expenses recognition for accounting and public reporting purposes. We see no need for the rate order to specify the amount included as long as the issue has been addressed and the amount in question has not been specifically disallowed.

Issue 2.6: Does indication in a rate order of the treatment accorded certain revenues and costs in determining rate of return provide an adequate basis for a utility to defer (or accelerate) the timing of revenue and expense recognition for accounting and public financial reporting purposes? If so, must the rate order specify the amount and how it affects the rate of return?

Rate recognition of revenues and cost through rate of return determinations, as contemplated in this question, are, to our knowledge, rare. However, if such ratemaking techniques were to be used for a particular transaction, we find it difficult to visualize a circumstance where there would be a sufficient nexus between a particular cost item and the rate of return allowed.

Issue 2.7: Does indication in a rate order of the treatment accorded certain costs and obligations in determining rate base provide an adequate basis for determining whether they should be recognized as assets or liabilities for accounting and public financial reporting purposes? Respondents should specifically cover: allowances for equity funds used in construction, inter-company profit included in assets, leases, and deferred income taxes.

Please refer to our general comments with respect to indications in a rate order of the treatment of certain costs and obligations in determining rate base and our comments on Issue 7 regarding the capitalized cost of equity funds. On the other specific issues we have the following comments:

1. Intercompany profits - We believe that if a regulatory commission allows recovery in rate levels of an asset which includes an element for intercompany profits, that such element is as much a part of the asset as any other element and should be so recognized.

2. Deferred Income Taxes and Leases - We believe that recognition of deferred income taxes or capital leases is not proper when the effects of accelerated depreciation is being flowed through for rate purposes or the lease is treated as an operating lease in the rate process. These items do not appear to qualify as either assets or liabilities under the definitions contained in the Exposure Draft (Revised) on Elements of Financial Statements of Business Enterprises because neither probable future benefits nor probable future sacrifices exist.

Issue 2.8: Does the use of a "fair value" rate base in setting a regulated enterprise's rates provide a basis for reflecting utility plant at that value in financial statements prepared for public financial reporting purposes?

No. We believe that the adjustment of a utility's asset to a fair value basis in a rate proceeding is a means of compensating the utility for general inflation. Under GAAP and the Uniform System of Accounts, the revaluation of assets is inappropriate for inclusion in a firm's basic financial statement. Furthermore, fair value is used only by a few regulatory commissions.

Issue 2.9 - Issue 2.13: Please refer to our general comments on these Issues.

Chapter 7 - Possible Impact of Rate Regulation on Accounting for Health Care Enterprises, and Chapter 8 - Possible Impact of Rate Regulation on Accounting for Other Regulated Enterprises.

We have not commented on the Issues presented in these chapters as we are not familiar with the ratemaking procedures for these industries.

Issue 3: Should any pronouncement issued by the Board identify specific industries affected?

No. The standards established should be clear enough to enable the ready identification of industries currently affected. Such standards should enable future determinations as to which industries are then affected.

Issue 3.1: If identification is required, to what specific industries should the pronouncement apply?

Not applicable in view of our response to Issue 3 above.

Issue 4: Should the effects of rate-making transactions applicable to prior periods be accounted for as prior period adjustments? If so, should the matter be included in a pronouncement coming out of this project, or should it be covered in an amendment to or interpretation of Statement 16?

Yes. As we commented in response to Issue 2, we believe that, to the extent practicable, financial statements of utilities should reflect the economic realities of the rate processes of the regulatory body or bodies that set the utilities' rates. If the effects of rate refunds are not accounted for by prior period adjustments with restatement of prior years' financial statements, utilities' earnings will either be overstated or understated with resultant confusion to users of the financial statements. We believe that recognition that rate refunds are proper prior period adjustments should be dealt with in this project and also through amendment of Statement 16.

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1. An FASB Statement requires retroactive application on a cumulative adjustment, but the change will be applied prospectively for rate-making purposes?

2. Following a change prescribed by the FASB, rates that had been established on a basis that reflected the prior principle continue in effect.

We believe that the accounting should be consistent with the rate-making in both instances.

Issue 6: Should any pronouncement dealing with the impact of rate regulation specify mandatory application?

Yes. It would be a waste of time to go through the lengthy process of evaluating the effects of rate regulation on accounting for regulated enterprises and then issue a pronouncement that could be optionally applied. The creditability of the pronouncement would be undermined unless it specifies mandatory application.

Rate recognition of revenues and cost through rate of return determinations, as contemplated in this question, are, to our knowledge, rare. However, if such ratemaking techniques were to be used for a particular transaction, we find it difficult to visualize a circumstance where there would be a sufficient nexus between a particular cost item and the rate of return allowed.

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Yes. It would be a waste of time to go through the lengthy process of evaluating the effects of rate regulation on accounting for regulated enterprises and then issue a pronouncement that could be optionally applied. The creditability of the pronouncement would be undermined unless it specifies mandatory application.

Issue 7: Does the ratemaking process support reporting the contra credit to any capitalized cost of equity funds used in construction as current income?

Yes. The asset value has been increased due to well-established regulatory procedures, and recovery thereof is virtually assured. The question then becomes one of the timing of income recognition. While Cash recovery does not take place until after the plant is completed, the income is generated simultaneously with the increase in asset value as construction takes place.

One of the principle purposes of the AFUDC allowance is to provide a current return to stockholders for the use of their capital which has been invested in the construction program. If the return is not recognized as current income, earnings will decrease during the construction period and the value of stockholders' interests will be artificially lowered merely because the return is in a form similar to a long-term interest bearing account receivable, rather than cash.

Issue 8: Should the financial statement of a regulated enterprise disclose the effect of differences between those statements and what they would be if the enterprise was nonregulated? Should the same standards apply to both the balance sheet and the statement of income?

No. We believe that financial statements that reflect the results of the ratemaking process present fairly the operating results of utilities. Therefore, we believe that regulated enterprises should not be required to disclose differences between the manner in which a transaction is treated for accounting purposes by a regulated company and a nonregulated company in either the balance sheet or the statement of income.

Issue 8.1: Should the effect of rate-making be disclosed on the face of the income statement?

No. See our response to Issue 8.

Issue 8.2: If disclosure of the effects of ratemaking is made on the face of the income statement, is any additional disclosure necessary in notes to the financial statements? If so, why?

Issue 8.2 is not applicable because of our response to Issue 8.

Issue 8.3: If disclosure of the effects of rate-making is considered necessary but not made on the face of the financial statements, what disclosure should be made in notes to financial statements?

None. See answer to Issue 8. However, we believe that the notes to the financial statements should disclose significant accounting and ratemaking policies.

Issue 9: What disclosures of rate-making treatment should be made if it is concluded that such treatment should not affect the application of generally accepted accounting principles? Specifically:

1. Should the effect of material differences in the way revenues and expenses are treated for rate-making purposes and for financial reporting purposes be disclosed?

2. Should the estimated impact of these differences on future revenues be disclosed? If so, how -- by year, by bands of years, or in total? Should a similar impact on net income be disclosed?

3. Should material differences for property, plant, and equipment (or other assets and liabilities) between the amounts included in the balance sheet and amounts included in the rate base be disclosed?

We have previously stated our belief that, to the extent practicable, financial statements of regulated companies should generally reflect the economic realities of the rate process of the regulatory body or bodies that set the regulated companies rates. If the FASB should conclude that the rate process should not affect the application of generally accepted accounting principles, we believe that the information shown in financial statements would be misleading and that attempts to remedy the defects through disclosure would only tend to confuse readers of the statements.

Issue 10: What other information, if any, should be disclosed about rate making? Where in financial reporting should that additional information be disclosed?

We do not believe disclosures, other than as suggested in our response to Issue 8.3, are necessary.

Issue 11: Should any new standards on accounting for the impact of rate regulation be applied:

1. Retroactively by restating all prior periods presented?

2. Retroactively by including a cumulative adjustment in the current period?

3. Prospectively?

In general, we do not believe that new standards of accounting should be made retroactive because this implies that the previous standards were incorrect when they were, in fact, "generally accepted" in those prior periods.

Sincerely yours,

L. H. Drennan, Jr.
Chief Accountant

THIRD SESSION, Wednesday, May 21, 10:15 a.m.

Concurrent Session B-2

VALUE-ADDED TAX AS IT RELATES TO PUBLIC UTILITIES

CHAIRMAN: William L. Tiffany, Vice-President and Chief Executive Officer-North Dakota, Northwestern Bell Telephone Company

SPEAKERS: Bernard Topper, Assistant General Counsel-Tax, General Telephone and Electronics Corporation

Bruce Davie, Chief Tax Economist, Ways and Means Committee, U.S. House of Representatives

A BIRD'S-EYE VIEW OF A VAT
AS IT RELATES TO A PUBLIC UTILITY

Bernard C. Topper, Jr.
Assistant General Counsel - Tax
GTE Service Corporation

I will try to cover some of the possible effects that a value-added tax (a "VAT") may have on a public utility. This will necessitate a quick look at the nature and operations of a value-added tax. To do this, we will put on blinders and focus solely on a VAT, overlooking for the moment the key fact that, as proposed, the VAT is but a part of other proposed and very substantial changes in the federal tax law. At the end I would like to come back to the other changes and offer a few comments.

VAT

As I am sure most of you are aware, the concept of a value-added tax is not new. It has been considered before in the United States and is today a major form of taxation in Europe, especially in the common market countries, as well as in several other countries throughout the world. This experience with a VAT in operation provides a wealth of information to a country considering the adoption of a VAT. For example, it quickly becomes clear that a value-added tax can take many forms. The drafters of the proposed VAT for the United States have elected to cast it in the form of a so-called "invoice" and "consumption"-type VAT. To my way of thinking, the drafters of the VAT have done their homework well and have selected the best type of VAT.

A VAT is a tax on consumption and, as compared to an income tax, is designed to encourage or, at least, not to discourage savings and investment. This basic purpose underlying the enactment of a VAT is most important to a capital-intensive public utility industry.

Income taxes on capital, such as the present corporate income tax and the individual income tax on interest and dividends, reduce the after-tax return on savings and investment. As a result, these taxes are thought to encourage present, rather than future, consumption. Let me try to explain this by means of an illustration.

If there were no taxes at all, a person who has $10,000 of income could decide to spend (or consume) the $10,000 this year or to save the $10,000 and, assuming a 10% interest rate, spend $11,000 next year. Thus, the individual can consume 10% more next year by saving now. If, on the other hand, we have an immediate 50% income tax on the $10,000, the person has the option of spending the remaining $5,000 this year or saving the $5,000 for a year and earning interest at a 10% rate on the $5,000. But, if the individual saves the $5,000, a 50% income tax will be exacted on the $500 of savings interest, so that, by saving for a year, the individual can spend $5,250, rather than the $5,000 that could have been spent last year. Thus, by saving for a year, the individual's buying potential is increased by only 5% - from $5,000 to $5,250 - not by 10% as would have been the case if there were no taxes. For this reason, an income tax is thought to encourage present consumption.

A value-added tax is designed to bridge this gap. Thus, if there were only a VAT, which is tax on consumption, and an individual receives $10,000 of income, to keep the figures the same, we will assume that $5,000 could be spent this year (the remaining $5,000 being paid as a 10% value-added tax on consumption) or the individual could save the $10,000 and next year spend $5,500, paying a VAT of $5,500, an increase of 10% spending power. The key fact is, with a tax on consumption, a person by saving for a year would be able to consume 10% more next year, just as would have been the case if there were no tax, not 5% more as would have been the case with a 50% income tax.

This is the theory of a VAT and why it is thought by many to encourage savings and investment. As Secretary of the Treasury Miller has pointed out in his testimony before the Ways and Means Committee relating to a value-added tax, this type of analysis compares a "pure" consumption tax with a "pure" income tax levied on all forms of capital. Neither the proposed VAT nor our present federal income tax are "pure" taxes. For example, home ownership, pension reserves and assets eligible for the investment tax credit and accelerated depreciation receive favorable income tax treatment. Similarly, not all forms of consumption would be taxed under the proposed VAT. Items such as food, housing and medical care would be exempt. Thus, in theory, a VAT should encourage savings and investment. In practice, it is, perhaps, less clear to what extent this goal will be accomplished.

Let's take a look now at the mechanics of the proposed VAT. It is a relatively simple tax to understand and apply so long as it remains a broad-based tax on consumption with one rate - currently proposed to be 10% - and very limited exceptions. In essence, a VAT is a sales tax, but, unlike the typical state and local sales taxes with which we are all familiar, it is applied not only at the time of final sale, but to each sale in the production and distribution cycle. Like a sales tax, however, the burden of the tax falls on the ultimate consumer. This is accomplished by permitting a credit for the tax paid by all, except the final consumer.

A simple example will illustrate the credit mechanism and demonstrate the mechanics of a VAT system. Let us say that Tailor purchases enough fabric to make a suit of clothes from Textile. The fabric is worth $40. Under the proposed VAT system, Textile will sell the fabric to Tailor for $44, $40 for the fabric and $4 for the 10% value-added tax, which tax will be paid over by Textile to the federal government. Tailor, in turn, takes the fabric and its employees apply the necessary labor to make a suit of clothes for which Tailor wants to receive $100, representing $40 paid for the fabric, $50 paid to Tailor's employees and a $10 profit. Tailor will sell the suit to Clothier for $110 - $100 plus $10 for VAT. By virtue of the credit mechanism, however, Tailor will turn over to the government, not the $10, but $6 receiving a $4 credit for the VAT textile previously assessed on the purchase of the fabric. Thus, in terms of the value-added tax, Tailor is made whole - he collects $10 and, in total, pays over $10 to the government. In the final step of the distribution chain, Clothier sells the suit to Consumer for $150 plus a 10% VAT of $15, or $165, pays over only $5 to the government, receiving a credit for the $10 VAT on its purchase of the suit. The end result -- the ultimate purchaser pays $15 of VAT, the government receives $15, and everyone else in the production and distribution chain is made whole. All very simple.

Now, let's go one step further and assume that Tailor, recognizing the advantages of mechanization, purchases a new sewing machine worth $500. It is a purchase of property and, therefore, subject to a VAT. Presumably, Tailor would pay $550 for the machine--$500 plus a $50 VAT. But, does Tailor recover the $50 VAT?

Countries that have a VAT system have dealt with this question in differing ways, some allow the purchaser of a capital asset to recover the value-added tax immediately, some allow no recovery of the tax, and still others permit a VAT on capital purchases to be recovered, but only ratably over the life of the capital asset. The proposed VAT for the United States permits the immediate recovery of VAT paid for capital assets. Thus, going back to our earlier example for a moment, Tailor collected a $10 VAT on the sale of clothes and, applying a $4 credit from the VAT paid on the purchase of the fabric, paid $6 to the government. To reflect the purchase of the sewing machine, Tailor will now be entitled to a further $50 credit - the VAT attributable to the machine - and, hence, to a $44 refund from the government.

With this background, let's take a look at some of the possible problems a VAT may produce for a public utility. You may well have some additional thoughts.

<u>Working Capital Considerations</u> - I suspect that a VAT may lead to additional working capital requirements for a public utility. Under the proposed VAT, a utility, as a seller of goods or services, would be required to report its sales subject to VAT and pay over the applicable 10% VAT for all transactions within a given quarterly reporting period. The return is due within one month after the close of the period. Whether a transaction falls within a reporting period is determined by the accounting method a utility uses in keeping its books. For a utility on the accrual basis method of accounting, a transaction will fall within the reporting period for which it properly accrues income (or loss) on the sale. Thus, a utility on the accrual method of accounting will find it is responsible for a 10% VAT on sales made to ratepayers during a given quarterly period even though the ratepayer may not have yet paid for the service. Ratepayers who do not pay within a month or so - depending on the billing date - may produce additional working capital requirements. In addition, monthly deposits of estimated tax liability may be required during each quarterly period. If the monthly deposit requirement is also based on an accrual method, a similar problem may be present.

On the other side of the coin, of course, a cash flow benefit may result from purchases made by a utility which are accrued on its books for a given reporting period, but which remain unpaid at the time a utility receives a credit.

There is another provision in the proposed VAT which also may require additional working capital for a utility. Utilities are a significant provider of services to governmental entities and to charities. In order to exempt them from the payment of a VAT, the proposed VAT contains a "zero-rating" to exempt the final sale to these entities from the VAT, while permitting the seller, here the utility, to recover the VAT is previously paid on its related purchases of goods and services by means of the credit mechanism I mentioned earlier. This may produce a fairly significant cash flow problem to a utility since it will be required to pay a VAT on its purchases, but will receive no VAT funds on its sales to these "zero-rates" entities. As a result, I would expect that utilities will have additional working capital requirements to provide the necessary "float" to overcome the timing differences between their payment of a VAT, and its recovery. For these reasons, I suspect that utilities will find that a VAT would require additional working capital.

Uncollectibles - A further problem may arise as a result of uncollectible bills of ratepayers. As presently drafted, a VAT would have to be paid by a utility for the period in which a sale is accrued. If a ratepayer ultimately fails to pay his bill, including the portion attributable to a value-added tax, there is no method under which a utility can recover the VAT it has paid over to the government. Thus, to the extent a ratepayer fails to pay a bill, not only does a utility lose the amount of the bill, it will also suffer an additional 10% loss in the form of a VAT. Several foreign countries with a VAT permit some type of adjustment to reflect uncollectibles and, I would hope, that the proposed VAT will be revised to include a provision for bad debts as an offset to a VAT along the lines presently allowed in the Internal Revenue Code.

Costs of Administration The VAT has the potential of raising large revenues for the federal government at a relatively low cost to it, in part because the administative burden is borne by the business community. Clearly, the installation of a VAT would require utilities - and all businesses - to make operational and accounting changes and to train employees. This would be an additional cost since the VAT proposal would not replace any existing taxes.

The on-going compliance costs would depend to a large extent on the complexities of the tax. As long as the VAT remains a broad-based tax with one rate with limited exceptions and special rules, the on-going administrative costs may not be too heavy. In Denmark, which is one of a few countries where the VAT has remained a simple tax, the tax return is made on the back of a postcard. The taxpayer enters five figures - the tax collected on sales, a credit for the tax paid on purchases, the difference between the two, which is the tax liability, and the aggregate amount of exports and imports.

Looking at the world-wide experience with a VAT, and at our own experience with the federal income tax, I am doubtful that a VAT will long remain a relatively simple tax. Over time, people are likely to advance a host of political and economic reasons for changes in a VAT, thereby complicating the law and its administration. I also find little comfort that the VAT will remain a simple tax when I look at the almost limitless exceptions contained in the state and local sales tax laws.

Increase in State and Local Taxes - A utility would be responsible for paying a VAT to the federal government on its sales to ratepayers. Presumably, it will obtain the funds for this purpose by increasing its charge for services. An increased charge, the base on which state and local gross receipts and sales taxes are calculated will result in a corresponding increase in these taxes.

All of these additional costs associated with a VAT - namely, additional working capital requirements, a tax on uncollectibles, the unavoidable costs of administration and the additional state and local taxes - would, I presume, be reflected in a utility's cost of service and result in additional charges to ratepayers. Obviously, these additional costs are not unique to a public utility - other businesses will encounter similar costs. I suspect, though, that a VAT will cause the cost of utility services to increase disproportionately to the increase in most other goods and services for two reasons: first, utilities, more than most, are subject to local gross receipts taxes which taxes will increase as a result of a VAT and, secondly, utilities, more than most, may find that VAT imposes additional working capital requirements as a result of their sales to governmental utilities and charities.

From the standpoint of a utility, the installation of a VAT will cause an additional problem. The VAT imposed on a utility in connection with its sales could not be passed on to a ratepayer until utility rates were permitted to be increased by a regulatory commission to reflect the tax. A time lag would be encountered between the payment of a VAT by a utility and the inclusion of VAT in new rates. A VAT incurred during the interim would be borne by the utility.

So far we have considered a VAT by itself, as if it were a new tax enacted in a vacuum. This is obviously not the case. The VAT, as currently proposed, serves as a vehicle to fund substantial changes in the federal income and social security taxes which are designed to accomplish the economic objective of encouraging capital formation in order to improve productivity and reduce inflation and unemployment. This objective - the encouraging of capital formation - is critically important to public utilities, especially in these days of high inflation when utilities, because of their highly capital-intensive nature, probably suffer more than any other industry from the ravages of inflation.

Inflation, coupled with the current ratemaking method by which a utility is permitted to recover its capital, produces a serious problem for utilities. Typically, for ratemaking purposes, a utility is permitted to recover its capital on a straight-line basis over the life of the plant dedicated to public service. With current inflation rates, this results in a serious capital erosion for a utility. If, for example, a utility were to invest $1,000 in plant and equipment in year 1 and were to recover that $1,000 over the life of the property, say 16 years - the average life of telephone industry equipment - inflation will have produced a very serious erosion of that $1,000. At an annual inflation rate of 10% - a modest rate by recent standards - the utility would recover only $489 in terms of constant dollars - an erosion of over 50% of a utility's investment. To illustrate it another way, the dollar that is invested today and recovered in the 16th year is worth only $.22 given a 10% inflation rate.

As a result, I would think that the public utility industry would welcome with open arms any change in the tax laws which will assist it in attracting, and in recovering, its capital. When measured against this overwhelming benefit, the problems associated with installing a VAT pale in significance.

The key question then becomes - will the proposed changes in the federal income and social security laws that go along with a VAT provide substantial assistance in alleviating the utility industry's need for capital. I do not believe that we yet have the answer to this question. I would, however, like to close with two comments that bear on this question and that may not be readily apparent.

One of the proposed changes is a reduction in the maximum corporate income tax rate from 46% to 36%. As you know, the present provisions of the Internal Revenue Code require that, in order for a utility to be eligible for the tax benefit of accelerated depreciation, the tax benefit must be "normalized." The purpose of the "normalization" provisions relating to accelerated depreciation is to provide an additional, temporary source of capital to a utility in the form of an interest-free loan. This is accomplished by placing in a tax reserve, rather than "flowing-through" immediately to the ratepayers in the form of reduced rates, the difference in a utility's taxes which result from the use of accelerated depreciation as compared with straight-line depreciation.

A reduction in the corporate income tax rate would result in a reduction in the amount of this tax benefit to a utility and, therefore, decrease the amount of temporary capital made available to it. Let me explain this by means of an example. If a utility acquires a $1,500,000 asset with an expected useful life of 15 years, depreciation for the first full year, computed on a straight-line basis, would equal $100,000. Accelerated depreciation, using a double-declining balance method would be $200,000. Assuming the utility elects to use accelerated depreciation for tax purposes, the difference in tax resulting from the use of these different methods of depreciation is required to be "normalized." With a reduction in the corporate tax rate, the difference in a utility's tax computed using straight-line, on the one hand, and accelerated depreciation, on the other, will decrease, with the result that the amount of temporary capital provided to a utility will also decrease. Using the figures in the above example, at a 46% rate, a utility will derive $46,000 of temporary capital in the first year. At a 36% rate, it would derive only $36,000, a reduction of 21.73%. Thus, this portion of the proposed VAT would actually exacerbate a utility's need for capital.

The proposal also contains a change that would be of tremendous assistance to a utility in raising additional equity capital - the tax deferral of dividends in common stock. This proposal is also pending in two other bills, one each in the House and Senate, in which the bill is solely dedicated to this item. There are substantial arguments for the passage of these two single-issue bills, including a study done by Robert Nathan Associates which shows that there is only a modest initial cost to the Treasury of $300 million and that, by the third year, the bills would generate $600 million in Treasury revenues through increased economic activity. I would like to think these bills will succeed on their own merits. If so, one of the key provisions of the present VAT bill in terms of assisting utilities in raising capital will be rendered moot.

The thought I want to leave with you is this - the basic purpose of the VAT bill, considered as a whole, is one that we in the public utility industry can strongly support. We need to consider seriously, however, whether, as presently drafted, it will accomplish its purpose for utilities. To the extent we have problems, now may be the time for us to voice our objections and to seek the necessary changes in the bill.

THE VALUE ADDED TAX AND ITS IMPLICATIONS FOR PUBLIC UTILITIES

Bruce F. Davie
Chief Tax Economist
Committee on Ways and Means
U.S. Congress

INTRODUCTION

For the first time a value added tax (VAT) is being seriously considered by the Congress. By serious consideration, I mean that a bill including a VAT was introduced (H.R. 5665) and initial hearings held by one of the tax-writing committees of the Congress.1/ Al Ullman, Chairman of the Committee on Ways and Means, introduced the Tax Restructuring Act of 1979 on October 22, 1979. He introduced a revised version - the Tax Restructuring Act of 1980 - on April 2, 1980 (H.R. 7015). Russell Long, Chairman of the Senate Finance Committee, has publicly indicated his support for the general concept of using the proceeds of a VAT to reduce existing taxes. When the chairmen of both tax-writing committees indicate their support for a major change in U.S. tax policy, the Administration, business, labor, and public interest groups begin to study the issue in earnest, and individual citizens begin to make their views known.

The basic thrust of Chairman Ullman's proposal is to reduce social security tax rates, cut individual and corporate income taxes, and replace the lost revenues with the proceeds of a consumption-based VAT at a general rate of ten percent.2/ The income tax cuts include rate reduction, a major simplification and liberalization of depreciation, savings incentives, an expansion of the earned income credit, a provision to reduce the "marriage penalty", and making the tax credit for the elderly refundable. A portion of the VAT receipts would be transferred to the Social Security Trust Fund such that the flow of receipts into that fund would be neither greater nor less than it would have been in the absence of the rollback in payroll tax rates.

The Chairman's initial proposal implied, at 1981 levels of income, net receipts of $130 billion from the VAT, and payroll and income tax cuts of the same magnitude. The revised proposal would not impose the VAT on food, housing, or medical care. The initial proposal imposed a VAT at a five percent rate on these forms of consumption. The revision implies VAT receipts of about $115 billion and a comparable package of tax cuts. The Chairman also included, as an amendment to the Congressional budget process, a limitation on Federal spending to further emphasize his intention that the VAT be used only as a means of reducing existing taxes, not as a mechanism for expanding the size of the Federal government.

The fundamental purpose behind this proposal for radically restructuring the American tax system is to accomplish a shift in the allocation of the nation's productive resources away from consumption toward investment.3/ There appears to be widespread public understanding that a larger share of GNP needs to be devoted to investment.4/ The recent decline in the amount of capital each worker has to work with and the resulting lag in productivity growth must be redressed. Basic industrial capacity must be renewed in response to the radical increase in energy costs relative to capital and labor costs. Investment is also needed to meet legitimate environmental, health and safety concerns. Over-reliance on income taxes discourages savings and investment and encourages leisure and consumption. The over-reliance becomes even more critical when high income tax rates have to be maintained because of the overt erosion of the income tax base through a panoply of tax provisions designed to accomplish social objectives other than revenue generation and the covert erosion through the growth of the "underground" economy.

The Chairman's proposal has been very controversial and at the moment lacks widespread political support, and for clear reasons. There is concern about the inherent regressivity of any consumption-based tax, the short-run inflationary consequences of a VAT, the public administrative and private compliance costs of a new tax, and the implications of a new revenue source for the long-run growth of Federal government activities. A national retail sales tax or a progressive expenditure tax have been suggested as forms of a consumption-based tax superior to a VAT.5/ These are legitimate concerns and will be fully explored in future Congressional hearings and in public commentary. The purpose of this paper is not to debate these issues, but to focus on a narrower range of questions which should be of concern to experts in the field of public utility regulation.

INCOME AND PAYROLL TAX REDUCTIONS TO BE FINANCED WITH A VAT

As might be expected, there is more enthusiasm for tax cuts than for the VAT as a means of providing an alternative revenue source. Chairman Ullman's proposal calls for reducing the social security tax rate for both employees and employers by 1.8 percentage points below those specified by current law. The corporate tax rate would be reduced by 10 percentage points - from 46 to 36 percent. Among the savings incentives is a dividend reinvestment provision that is of special interest to public utilities. It would allow deferral of tax on up to $1,500 of dividends per year under qualified dividend reinvestment plans. The major feature of such a qualified plan is that the dividends be reinvested in newly issued stock.

The Chairman's proposal includes a major simplification and liberalization of depreciation. The proposal is built around the concept of open-ended accounts for tangible personal property. Four accounts would be established with capital cost recovery periods of 3, 6, 9 and 12 years respectively. Assets would be categorized in one of these four accounts by taking the current midpoint guideline life and reducing that life by 35 percent.

If the resulting time period does not equal 3, 6, 9 or 12 years exactly, the asset would fall into the account with the next shorter recovery period. Each year the taxpayer would add to the basis in each account acquisitions, using a half-year convention, subtract out dispositions and the prior year's depreciation. Depreciation for the year would be determined by multiplying the basis so calculated by a "recovery percentage". The recovery percentage reflects the number of years in the recovery period and the depreciation method elected for that year. The depreciation method can be either 200 percent, 150 percent, or 100 percent of the straight line rate.

The full investment tax credit would be allowed for assets in accounts with recovery periods of 6 years or more; 60 percent of the investment tax credit would apply to assets with a recovery period. The only exception to this mandatory depreciation system for tangible personal property is for public utility property. Under the bill, the present 20 percent variance allowed under the ADR depreciation would be increased to 35 percent for public utility property. This special treatment was proposed because public utility property presents a special problem in any attempt to simplify and liberalize depreciation. Some public utility property is very long-lived and 12 years might be too short a recovery period. Public utilities are generally familiar with the ADR system and use it, so an increase in the ADR variance seemed to be appropriate. The problem is further compounded by the normalization flow-through questions. 6/

For structures taxpayers could elect to use lives at least 35 percent below present guideline lives. For buildings whose guideline life is more than 45 years, a 30-year life could be elected. If the guideline life is 45 years or less, 25 years could be elected. Where one of these lives is elected, that life must be used for the building and all of its structural components. If the taxpayer makes this election, the useful life cannot be challenged by the IRS.

Whatever the final outcome may be of any change in depreciation for tax purposes and corporate tax rates, there is a clear principle by which the outcome can be judged. The tax system should be neutral so that the after-tax rates of return to investments in different industries bear the same relationship relative to one another as pre-tax rates of return. Accelerated depreciation and the investment tax credit ought not to be denied to investments in public utilities merely because these industries are regulated.

The complete set of tax reductions included in the Tax Restructuring Act of 1980 are listed in Table 1, along with revenue estimates for calendar year 1981.

APPLICATION OF THE VAT TO PUBLIC UTILITIES

Massive reductions in income and payroll taxes are not possible without an alternative source of revenue. In an

TABLE 1

REVENUE ESTIMATES
OF THE
TAX RESTRUCTURING ACT OF 1980

(Billions of dollars)

	Calendar 1981
Social Security Tax Reduction:	
Employee	21
Employer	21
Self-employed	1
Total, Social Security Tax Reduction	43
Individual Tax Reduction:	
Rate reductions	27
Earned income credit, AFDC, & credit for the elderly	5
Liberalized retirement savings	2
Dividend reinvestment	1
Deduction for lesser-earning spouse	5
Total, Individual Tax Reductions	40
Business Tax Reduction:	
Rate reductions	22
Simplified depreciation and investment credit	10
Total Business Tax Reductions	32
TOTAL TAX REDUCTIONS	115
VALUE ADDED TAX RECEIPTS	115

Note: These estimates are rounded to the nearest billion.

economy with deeply embedded inflationary pressures and expectations, tax cuts large enough to shift resource use away from consumption to capital formation cannot be enacted if the result is a huge increase in the Federal government's deficit. It is also unreasonable, in my judgment, to expect that Federal spending can be cut so as to significantly shift resource use away from the provision of goods and services to the government or away from consumption financed out of government transfer payments.

The alternative revenue source envisioned in the Tax Restructuring Act is a consumption-based value added tax applied generally at every stage in the process of production and distribution.7/ The so-called "credit" method would be used. Every firm would be liable for a VAT at a 10 percent rate on its sales, but receive a credit for the VAT paid on purchases, including capital goods, from other firms. If purchases from other firms exceeded sales, the net credit would be refundable.

The sales of public utilities would generally be subject to the VAT. A major exception would be sales to government which are zero-rated under the Chairman's proposal. The value of sales upon which the VAT would be applied would be gross of any other Federal excise tax, but net of any State or local government excise tax.

The VAT would be applied to the commercial-type activities of governments, both state/local and Federal, even though no tax would generally be imposed on the providing of property or the performing of services by a government entity. This means, for example, that the VAT would apply to electricity sold by a municipally-owned power plant in the same way the VAT would apply to the sale of electricity by a privately-owned utility. Neutrality as between the sale of similar goods and services by governments and private firms is an important feature of the VAT.

If the Tax Restructuring Act, or some close approximation to it, were enacted, regulatory agencies would presumably have to allow the VAT to be fully reflected in rates, but also adjust rates to reflect the payroll and income tax reductions.

THE OUTLOOK FOR A VAT AND TAX RESTRUCTURING

Without any groundswell of political support for Chairman Ullman's proposal at the moment, should the possibility of an American VAT simply be dismissed? It seems quite possible to me that over the next few years a political consensus could emerge concluding that a faster rate of capital formation is so essential that (1) a major change in the American tax system is necessary and (2) the change must take the form of a shift away from taxes that discourage savings, investment, and work toward greater reliance on consumption-based taxes. As heavily capital intensive industries, public utilities have a vital stake in the emergence of that political consensus. If the consensus does emerge, a VAT could be considered as one of several alternative forms of a consumption tax. One of the alternatives may become a tax on only one item of consumption - gasoline. A national sales tax is a theoretical, if not political, alternative. Finally, the income tax might be loaded up with special savings incentives to the point where it became closer to a progressive consumption tax in the classical sense. In short, I do not think that the issue of a VAT in the context of tax restructuring is going to go away. Public utility industries and regulatory bodies should begin to study - if they haven't already - the implications of a VAT and tax restructuring as it would affect their own particular circumstances. The result of that kind of study effort should be presented to the tax-writing committees as future hearings on this proposal are held.

FOOTNOTES

1/ There was a flurry of interest in the VAT in the early 1970s in response to a proposal from the Nixon Administration to use the proceeds from a VAT to replace state and local property taxes as a financing source for elementary and secondary education. In response to a request from President Nixon, the Advisory Commission on Intergovernmental Relations prepared a report on the issue and recommended against the President's proposal. See U.S. Advisory Commission on Intergovernmental Relations. The Value-Added Tax and Alternative Sources of Federal Revenue. Washington, 1972. See also U.S. Congress. Joint Economic Committee. The Value-Added Tax. Hearings (92nd Cong., 2nd Sess.) Washington, 1972.

2/ For an explanation of the initial Ullman proposal, see U.S. Congress. Committee on Ways and Means. Hearing Announcement on the "Tax Restructuring Act of 1979" (H.R. 5665), (96th Cong., 1st Sess.) Washington, October 23, 1979. The revised proposal is described in the "Tax Restructuring Act of 1980" (H.R. 7015), (96th Cong., 2nd Sess.) Washington, April 10, 1980.

3/ See Al Ullman, "Restructuring the Tax System". Challenge, March/April, 1980.

4/ See the testimony included in U.S. Congress. Committee on Ways and Means. Tax Restructuring Act of 1979. Hearings, Part I. (96th Con., 1st Sess.) Serial 96-50. Washington, 1980. This volume includes an extensive bibliography on the value added tax prepared by the Congressional Research Service of the Library of Congress.

5/ The same issues discussed below, which are involved in applying a VAT to public utilities, would be raised if any other form of broad-based consumption tax were considered. The base of an expenditure tax would equal income minus savings and be taxed at progressive rates. For a debate on the issues raised by such a tax, see Joseph A. Pechman, Ed. What Should Be Taxed: Income or Expenditures? (Washington: The Brookings Institution, 1980).

6/ For a good analysis of the flow-through/normalization controversy, see U.S. Congress. Committee on Ways and Means. Description of H.R. 3165 and H.R. 6806 Relating to Accounting Treatment of the Investment Tax Credit and Accelerated Depreciation for Public Utility Ratemaking Purposes, (96th Cong., 2nd Sess.) Washington, April 14, 1980.

7/ A general familiarity with the basic structure of a consumption-based VAT implemented through the credit (or invoice) method is assumed in what follows. For good exposition, see R. W. Haber and Michael E. Trebling, "The Value-Added Tax -- A Review of the Issues", Review, January, 1980, Vol. 62, No. 1, Federal Reserve Bank of St. Louis. The credit method is used by Western European and other countries which use a VAT. This is the form of VAT incorporated in H.R. 7015. Other forms of VAT have been discussed in the literature.

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A VITAL NEED - NEW APPROACHES TO DEPRECIATION

Richard A. Rosan

These are troublesome times; as a nation we have been suddenly brought up short. As a result, we see in Congress, in the business community and in academia a reexamination of many economic policies and concepts that have been accepted - knowingly or unwittedly - for many years. Such reexamination results from several presistent trends:

> First - escalating inflation. Finally recognized as the nation's No. 1 problem, the Congress, the Administration and people from all walks of life are seeking means to cope with it. Persistent inflation since 1946 is a fact. Makers of depreciation policy can no longer ignore it!
>
> Second - the nation's declining productivity performance to the point where we trail most developed nations in productivity gains.
>
> Third - increasing cost of capital. Many high grade bonds are selling at 50% to 60% of face value reflecting current interest costs which no doubt reflect lenders' fears of inflation. And, as part of higher capital costs is the strong trend toward shorter maturities. In the case of gas industry debt issues, 15 year sinking fund bonds with average life of 9 - 10 years are common place.
>
> Fourth - the dismal performance of utility common stock with many good utilities selling on the basis of 10% to 13% yields on current dividends. For many, the price is below book value.

These trends must be a source of concern and reexamination by every person in this audience concerned with depreciation policy.

Historically, depreciation has received most attention in two major areas - the allowable amount to be deducted for tax purposes i.e., a tax issue of importance to all businesses, and the dollars for depreciation to be allowed in utilities' cost of service.

As a broad generalization we can observe that in both areas - tax and utility rate making - the emphasis has been chiefly on service lives. We have placed great emphasis on studies of service lives (the Iowa Curves being an important tool); in the case of the natural gas industry there has been a slight bending of the methodology toward the life of gas reserves as a basis for estimating service life of the plant associated with such reserves.

My thesis today is that this narrow approach based on service lives must be revised, with increasing emphasis on the current economic and financial realities. The question must be discussed more in terms of capital recovery and capital formation than in terms of depreciation based on service lines.* As discussed below, in the area of tax depreciation, there is strong evidence that new approaches are being considered. With minor exceptions, I see no evidence of any significant movement in regulatory practices in the matter of depreciation. If Congress can appreciate the need for abandoning service life criteria for tax purposes in order to achieve economic and social objectives, then regulators must be prepared to consider book depreciation in broader terms, giving recognition to lenders' and investors' actions as a result of inflation and the needs of utilities for cash flow to service shorter life bonds and preferred stocks. Past policies dictated solely by the desire to keep rates down to present customers without considering the long run implications for the nation's progress and productivity must yield to present and future realities!**

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*Mr. William H. Comtois, a consultant on utility finance and regulation, supports much of the foregoing analysis in the P.U. Fortnightly, May 8, 1980 at page 19: "Capital formation is one of the most vexing problems facing utility managements today. Utility commissions which regulate rates have difficulty, in most areas of the country, granting rates in sufficient amounts to meet the needs of the utilities under their jurisdictions. Virulent inflation exacerbates the problem but is beyond the control of either the commissions or the utilities. Outdated valuation rules and depreciation practices restrict the cash that flows from writing off existing plant. Compounding these difficulties, some commissions thwart tax rules, designed by Congress to encourage capital investment, by insisting that the benefits of special rules be immediately distributed in the form of lower rates to consumers rather than being used to build plant."

**In preparation for this paper I requested a group of knowledgeable people in the utility industry to share their views on current regulatory depreciation practices. Almost everyone mentioned this problem: One noted: "Actually, higher depreciation rates result in an over-all saving to the consumer in the long run. However, most regulatory commissions fail to see this or may not wish to see it as the use of low depreciation rates results in lower revenue costs at the present time - surely a laudable action for any politician."

Another noted: "Probably the greatest concern at this time about depreciation rates is that state regulatory commissions are intent on keeping depreciation rate down for the simplistic and short-sighted reason that present retail rates are thereby kept lower**** The state regulatory commissions support low depreciation rates based upon studies which are premised upon the assumption that the future will be the same as the past." Unfortunately, as noted at the outset of this paper, the "present," much less the "future," is not the same as the past.

Another noted: "The present situation is subsidising the present Peter at the expense of the future Paul. Since increased depreciation rates reduce future rate base, return and fixed charges, the case can be made that increasing depreciation rates now could provide the least present worth of all future revenue requirements from customers in total. This argument, although true, has been politically unacceptable since most Commissions are more concerned

In making a plea for new approaches toward depreciation policy, it is realized that there are legal precedents and accounting practices that must be modified. To achieve this is not in my opinion an overwhelming task, provided commissions are willing to face up to the issues. In my opinion, it is essential that the effort be made - otherwise the ability of the energy providing industries to meet the energy needs of the nation may be unnecessarily difficult, if not impossible. In other words, the realities of inflation and of the financial markets cannot be ignored any longer.

In the mid-fifties there was much ferment and study of so-called economic depreciation.* At that time, inflation had reduced the value of the 1940 dollar by slightly less than half - a 55¢ dollar. Those who opposed at that time any recognition of price level adjustment argued that there would be a deflation as had been experienced after major wars. Paul McCracken gave a paper in early 1954 to the A.G.A.-E.E.I. Accounting Meeting in which he spent almost the entire paper to support his conclusion that a new, permanent plateau for the value of the dollar had been reached. "The evidence is increasingly clear that prices are now stabilizing at a new plateau, that the 100 cent dollar is gone, and that for the foreseeable future the purchasing power of the dollar will be roughly 55 cents relative to prewar." Professor McCracken then noted the unfavorable comparisons of utility earnings relative to industry generally and stated:

> "One of the problems involved in estimating this earnings lag is, of course, to get a meaningful comparison. Much of the capital in public utilities represents prewar investment. The result is that the current cost of providing service currently is correspondingly understated, and profits are overstated. The real purpose of a depreciation charge is to account for, as a current cost, that portion of capital expiring during the current period."

Professor McCracken's 55¢ dollar of 1954 has declined to an 18¢ dollar in 1980. Thus, the question is - Why hasn't something been done to recognize the problem noted by Professor McCracken in 1954? There are several explanations. First, a large number of persons believed in the possibility of deflation. Second, as noted in the footnote, the CPI increased steadily but at a fairly low rate from 1955 to 1972 - the index rising from 80 to 125.** Third, some tax

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about today's customers than they are about tomorrow's."

*A major study of an A.G.A. and E.E.I. Project Committee of the Accounting Committee in March 1955, re depreciation which would recognize the variable purchasing power of the dollar used this term "economic depreciation" recognizing other terms were used and appropriate: Price Level Adjusted Depreciation, Dollar Value Adjusted Original Cost Depreciation, and Capital Recovery or Capital Adjustment.

**The Consumer Price Index was 80 in 1955; 100 in 1967; 125 in 1972; and 233 currently. However, in terms of the cost of most utility plant, this seriously understates the decline in the pur-incentives, such as accelerated depreciation, gave lift to utilities. Finally, and probably most important, there were no strong signals from the financial community that traditional financing was in jeopardy. As to the latter point, it seems a fair observation that the investors took a long time to appreciate the eroding effect of inflation on the value of their savings. It was not until the early 1970s that the demand for shorter maturities on preferred stock offerings were demanded and the escalating interest rates on long term debt manifested itself.

The basis for the thesis of this paper is that the investors' thinking on inflation have changed and the need to prevent an erosion of the purchasing power of capital is uppermost in the minds of almost every person with savings.

There is no better illustration of the change in thinking than to examine the veritable revolution in Congress, supported by a large body of economists, on capital formation and the role of tax depreciation in meeting the nation's capital needs.

Let us review briefly these very significant developments:

First - in 1978, the capital gains tax was sharply reduced to encourage investment.

Second - the 1980 Annual Report of the Joint Committee of Congress chaired by Senator Bentsen disavows economic thinking focused on the demand side of the economy and recommends a "comprehensive set of policies designed to enhance the production side - the supply side of the economy." Chief among its 32 recommendations is a call for a modest $25 billion tax cut, but the Report emphasizes that 1/2 the cut shall be targeted at enchancing savings and investment. The Report specifies this shall be accomplished primarily by increasing the allowance for <u>business depreciation</u>. The economic model prepared in support of the Report suggests that the fight against inflation could be made through tax cuts such as a <u>reduction in depreciation</u> schedules.

Third - H.R. 4646 - the Capital Cost Recovery Act - and the companion S1435 have very strong co-sponsor support in both Houses. The following table illustrates the Bills' proposed rapid depreciation to recover for tax purposes various types of business assets:

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chasing power of the construction dollar. The Engineer News-Record, Construction Cost Index for 1955 was 61 and for 1972, 161 or an increase of 160%.

CAPITAL COST RECOVERY TABLE

Ownership Year	Class of Investment I	II	III
1	10%	20%	33%
2	18%	32%	45%
3	16%	24%	22%
4	14%	16%	
5	12%	8%	
6	10%		
7	8%		
8	6%		
9	4%		
10	2%		
	100%	100%	100%

Class I assets are generally buildings and structural components. Class II assets are generally machinery and equipment. Class III assets include automobiles and light weight trucks but would be limited annually to $100,000. Utility assets are included in this bill.

It is clear that this legislation proposes to largely abandon service lives and arbitrarily permit a fast recovery for tax purposes of invested capital. As one able economist told me recently - depreciation is merely a convention - so long as there is a consistant approach the convention can be any means of achieving sound end results. For him there is no magic in service lives.

Fourth - Development on April 2, 1980, Chairman Ullman of the Ways and Means Committee of the House introduced H.R. 7015, the Tax Restructuring Act of 1980. This is a far reaching act that would cut $115 billion in income and payroll taxes - of which $32 billion would be to business - "which badly needs a shot of new capital to expand and boost dangerously low rates of productivity. The United States today is the only industrialized country in the free world with a declining productivity rate." This $115 billion cut would be off-set by a $115 billion value added tax. Aside from reducing the corporate tax rate 10 points (46 to 36 percent), Mr. Ullman stated:

> "I add to my proposal a novel and productive approach to the crucial issue of capital cost recovery."

The cost of all depreciable property (other than utility property) would be classified in 1 of 4 recovery accounts with recovery periods of 3, 6, 9, or 12 years. It is specified the assigned recovery period must be at least 35% shorter than its midpoint useful life under the present ADR system. As to utility property placed in service in the taxable year beginning after Dec., 1980, the present 20% variance allowed under ADR is increased to 35%. It is unfortunate that Mr. Ullman makes the distinction between utilities and other businesses. This may be corrected as the matter moves through hearings and Congress.

The four developments described on the national economic and tax fronts support the point that there is a strong ground swell on the need for more rapid capital formation. The suggested approaches are significant, because as previously noted, they depart so markedly from "service life" thinking.

To augment one aspect of the capital formation problem as it relates to gas and electric utilities. Major energy supply projects now involve unprecedented capital requirements. For example, a synthetic coal gasification plant with a daily capacity of 250 million cubic feet will cost one and a quarter billion dollars. The eastern leg of the pipeline in the U.S. to bring Alaskan gas to the midwest will cost over one billion dollars. The gas industry estimates capital needs of 303 billion dollars between now and the year 2000, compared with a present total capital investment of only $65 billion. The magnitude of these capital requirements and the limits to availability of capital for the nation's total capital agenda demand a rapid recovery of capital so that it becomes available for reinvestment. Congress is correct in recognizing the need for faster write-off to promote capital formation and availability.

Now, for the regulatory commissions - Departure from past depreciation practices has been slight at best. In the case of natural gas facilities, tied to a particular source of gas, such as a pipeline transporting gas from a specific field, FERC has permitted higher depreciation based upon the gas reserves available. (See Memphis Light, Gas & Water Div. v. FPC, 504 F 2d 225 (1974).* Unit of production or unit of throughput depreciation has been used in some cases. As a gas supply shortage developed in the early 1970s, FPC, now FERC, allowed somewhat higher rates on main transmission pipelines - permitting rates up to 5 to 5½ percent on a straight-line basis.**

It should be noted that already as the gas supply picture improves, at least the staffs of commissions are suggesting these some-

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*It is interesting to note that a survey of over 30 FPC/FERC decisions on depreciation rates, this is the only one in which the agency adopted or accepted the management's proposed depreciation rate. In all offers, either a Staff's or Administrative Law Judge's recommended depreciation rate (lower than the management's) was adopted. This one-sided approach poses serious questions as to the ultimate responsibility for adequate depreciation accruals.

**This paper will not consider the highly misleading nature of straight-line depreciation rates based on so-called "average service life." For example, an average service life of 25 years produces a 4% rate. This fails, because of infant mortality and other factors inherent in an "average," to recover the total investment in 25 years - all the original dollars may not be recovered in less than 45-50 years!

what higher depreciation rates be reduced. Further, the use of gas reserves to fix rates of pipelines has not been extended to distribution facilities. The statistics give strong evidence that distribution companies are allowed extremely low depreciation book expense and thus have a relatively low percentage of capital recovery to total investment.*

Recently, FERC allowed a pipeline to include a small percentage (¼ of 1%) for what was termed negative salvage. Actually, a more proper description is a reserve for the cost of retiring the particular facility. Several things might be noted. A 9% straight-line depreciation rate was approved, suggesting a life of about 11 years. The ¼ of 1% for cost of retiring would aggregate less than 3% of the plant cost in 11 years. As the gas industry looks toward the retirement of off-shore producing platforms, the equipment thereon and the plants, costs of retiring based on 3 to 6 percent of the original cost will probably prove wholly inadequate. In fixing the ¼ of 1% rate, FERC refused to take into account the effect of future inflation on the cost of such retirement. If, as appears to me at least, the allowance for retirement costs is unrealistic, future customers will be called upon to pay for such retirements. Equity demands that adequate reserves be created by charges to the customers getting the benefits from the facilities - not future customers who may receive no benefit from the particular facility. Finally, the reserve for cost of retirement is to be deducted from the rate base. Thus, a more realistic rate for retirement costs will tend to reduce fixed cost charges to the benefit of customers.

Another development comes from New York, where it has been proposed that the regulation of rates to industrial customers be terminated and the additional revenues the utility charged industry being free of price control, be used to increase depreciation reserves.** This proposal is fraught with difficulties and legality.

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*Based upon data of corporate income and balance sheets of gas distribution and transmission companies in 1979 GAS FACTS, the following information was developed:

(i) The ratio of annual depreciation expense of $299 million to total gas distribution plant of $9,619 million is 3.10%; the ratio for transmission companies is 4.39% based on $1,157 nillion of annual depreciation expense and $26,347 million of plant.

(ii) The rate of depreciation expense to total revenue is 3.01% for distribution and 5.03% for transmission.

(iii) Accumulated depreciation to total gross plant is 27.97% for distribution and 47.98% for transmission.

**See N.Y. Public Service Commission, Op. No. 79-19 "Opinion and Order Determining the Relevance of Marginal Costs to the Regulation of Gas Distribution Companies."

It is part of the politically attractive pattern of charging as much to industry as possible and thereby spare the residential customer any rate increases. The issues involved in the proposal of deregulating industrial rates and pricing at the competitive level are too complicated to cover in this paper - suffice to say, it is not a solution to the much broader problem being discussed.

Where does the foregoing leave us?

First - with continuing inflation, it is easily demonstrated that current depreciation accruals based on low rates applied to original cost will not generate enough capital to replace equipment as it wears out or becomes obsolete and inefficient. Some will say that this is proper since depreciation is merely to recover dollars without regard to purchasing power. The validity of this view rests upon an assumption of a relatively stable dollar. This assumption has not been a valid one for a great number of years and currently no financial planning is made on such assumption.

The fact remains, if we are to have a continuing business, under present depreciation practices, the replacement of worn out or obsolete facilities entails some of the following:

(a) Depreciation plus retained earnings of stockholders to make up for the increased replacement cost finances the facilities. Presumably by rate adjustments, the shareholder is kept whole - a return on a larger investment. The consumer pays higher rates.

(b) The sum of depreciation plus retained earnings, (a) above, is not adequate to pay for the replacement of facilities. In this case, new capital is injected into the business. The shareholders' interests in the business are diluted since only the same business is being done.

In either of the cases noted, it is apparent that the enterprise is not recovering each year the cost of the plant required to maintain a going concern. This is the basis for stating that costs of doing business is understated, profits overstated and taxes are paid on phantom profits.

This situation would seem to point to economic or price level depreciation. While a transition to this may have been possible and wise in the 1950s when rates were fairly stable, the figures I have seen over the past ten years suggest that the needed rate increases are not politically possible. As a minimum,a long phasing-in period would be required.

Second - AT&T's equal life group procedure or the unit summation procedure would be an improvement. It is an improvement because the dollars invested in a limit of property are fully recovered at the time of retirement, assuming all estimated retirement experience is correct. The procedure is better than the average service life approach. However, the procedure still rests upon estimate service lives and in many cases long estimated service lives. It is this long service life estimate that is so disastrous to the company and investor in periods of rapid inflation. Thus, the unit summation procedure does not meet the financial realities of the 80s, at least for many utilities.

Third - The regulatory agencies have complete knowledge of the repayment schedules of long term debt. On major investments, the depreciation rates must be tied to those debt repayment schedules. Depreciation accruals must cover among other things, the repayment of debt under the sinking fund provisions. If a pipeline is financed 70% debt and debt must be retired over a 15 year life, depreciation as a minimum must recover 70% of the plant in 15 years. As to the equity, the shareholder has a right to a continuing business, without dilution of his interests. Regulatory agencies should allow, if requested by the company, a recovery of the equity investment on the same recovery period allowed for tax purposes, unless the company can show a shorter period is justified.

Finally - Unless we quickly recognize that inflation is destroying capital, as a nation, we will be eating up the capital seed corn that has been painfully created by the savings of all our people over the years. Stopping inflation is a matter of first priority. But, until we do, depreciation policies must be substantially revised. We must stop thinking in terms of depreciation tied to service lives. Instead, we must concentrate upon and use the terminology of capital recovery. Capital recovery on an accelerated basis is part of the concept of "capital formation." Capital recovered becomes part of the total capital available for investment. Yes, capital recovery is part of enterprise's cash flow - a matter of deep concern to financial analysts and informed investors. Congress is recognizing that capital recovery and capital formation have little, if anything, to do with service life.

Unless these new approaches are adopted, utilities will find their securities are saleable only at higher and higher costs to reflect the eroding effect of inflation. Capital formation is a recognized national need; depreciation policies can play a major role in meeting that need.

FIFTH SESSION, Wednesday, May 21, 1:15 p.m.

Concurrent Session C-1

FINANCIAL AND RATE-MAKING ASPECTS OF THREE MILE ISLAND

CHAIRMAN: Marvin S. Lieberman, Partner
Zuckert, Scoutt and Rasenberger

SPEAKERS: George A. Avery, Esq.
Wald, Harkrader & Ross

Gordon R. Corey, V.C. (Ret.)
Commonwealth Edison Company

RATEMAKING RESPONSES TO TMI

by
George A. Avery
Wald, Harkrader & Ross
Washington, D. C.

I am pleased to have the opportunity this afternoon to discuss the issues involved in regulatory responses to nuclear accidents. This is, in fact, the third time in the last year that I've given a paper on this subject. One could persuasively argue that the least significant fallout from that cataclysmic event in the history of nuclear power has been my involvement in the discussion of its consequences. It all began when I was asked to participate in a symposium last fall by addressing the ratemaking consequences of nuclear accidents. My paper was later published in the Public Utilities Fortnightly and came to the attention of lawyers for GPU, the owners of Three Mile Island. They asked me to develop testimony based on my observations at the symposium for presentation to the Pennsylvania Public Utilities Commission in the then pending rate proceeding involving TMI.

I agreed to do so and worked with Professor Guido Calabresi of the Yale Law School on testimony which we presented jointly during hearing sessions last February. In my symposium paper, I had cited Professor Calabresi's important and perceptive work involving an economic analysis of tort law, believing that his analytical approaches might also be useful to a commission faced with the ratemaking consequences of a nuclear accident.

In our testimony at the Pennsylvania Commission, we tried to provide a legal/economic perspective for the Commission in an attempt to assist it in deciding the difficult issues before it. I would like to review that perspective with you this afternoon.

It might be asked at the outset why any such perspective is necessary. Allowable items of expense and rate base are hardly new phenomena. The principles are clear. Expenses are allowed if they are reasonable and prudent; plant investment is included in the rate base if it is used and useful. A commission could simply apply these standards and reach the indicated result.

Of course, my research into cases dealing with those standards indicated that they allow considerable flexibility in their terms and that they do not dictate any single result in a case like TMI. Apart from this, however, I believe it is essential for commissions, and for those involved in such cases before them, to realize that there are important factors distinguishing the nuclear accident case from almost every other kind of rate proceeding.

First, the ratemaking result of a nuclear accident case may affect the very viability of the utility involved. This was expressly recognized in the recent Pennsylvania proceeding, where the Commission specifically ordered an examination of Met Ed's ability to provide continued service.

Second, in the usual rate case, the magnitude of the expense and rate base items challenged does not portend a profound change in the risks borne by investors. In the nuclear accident case, however, the stakes are so large that fundamental issues are raised as to the scope of the risk covered by the allowed rate of return.

Third, in most rate cases, the effects of the decision are confined to the utility involved, its ratepayers and its investors. A case involving a major nuclear accident, however, can influence decisions throughout the electric industry, as well as decisions of nuclear power suppliers. In this way, the decision can have an effect on national energy policy. Because of this link, it is incumbent upon a state commission dealing with rate consequences of a major accident to consider the national posture toward nuclear power as an integral part of its decision-making process.

Let me spend a few moments on this latter item. The assessment of national policy on nuclear power should be a realistic one. While there is a strong current of anti-nuclear sentiment in this country, there has been no societal determination that the very construction of nuclear plants is imprudent because of the risk of accident. On the contrary, our commitment to nuclear power has been repeatedly reaffirmed since the occurrence of, and in light of, the Three Mile Island accident. The Kemeny Commission did not endorse a moratorium on nuclear licensing. The President, in reacting to the Kemeny Commission report, expressed the view that licensing activities of NRC should not be held up more than six months. The Congress rejected strong efforts, in connection with the NRC appropriations, to impose a licensing moratorium. Since TMI, the National Academy of Science has issued a report, three years in the making, which exhaustively analyzes our energy needs and concludes that continued reliance on nuclear energy is essential. In no sense can it be said that our nation has rejected nuclear power having considered its risks, including those exposed by TMI, and its benefits.

These three factors, then, distinguish the rate proceeding involving nuclear accident consequences. They require the commission dealing with such a case to seek a profound and broad-based understanding of the issues involved.

In such a setting, it is not enough for a commission to reiterate general ratemaking principles enunciated in other, less portentous factual contexts. Rather, the Commission should understand that its decision to include or exclude plant investment of the magnitude affected by a nuclear accident does not turn on the reiteration of words like used and useful and of notions of imminence. Such a decision is in reality a choice as to the proper allocation of risk between investor and ratepayer. (Interestingly, equation of the "used and useful" standard with the concept of risk, as applied to TMI, was recognized by Steven McClaren, the Deputy Chief Counsel of the Pennsylvania Commission in a paper which he presented at a symposium in Hershey last July on the legal consequences of nuclear accidents. He stated that "used and useful property is property whose current operation carries acceptable risks, risks that are acceptable in the current social, political and regulatory climate." This perception of the issue was not reflected in the Commission's May 9 decision.)

The focus on risk allocation was a major theme of the testimony which Professor Calabresi and I presented to the Pennsylvania Commission. It was our view that the analysis should begin with the dual goals of risk allocation in accident law: satisfying society's notions of justice while allocating accident risks in a manner which is consistent with the most efficient allocation of society's resources, more specifically, in a manner which minimizes the risk of accidents and the cost of accident avoidance.

It was my view, then and now, that the joint goal of allocative efficiency and fairness is best served if a substantial portion of the costs of a nuclear accident are borne by the utility ratepayer. Let me review the analysis which underlies that view.

In most accident situations whose consequences a commission might encounter in the ratemaking context, this allocation of risk would be achieved through an insurance or risk-sharing scheme, the cost of which would clearly be recoverable through rates. (Incidentally, it is significant to note that insurance costs are allowed without reference to the utility's possible negligence in the accidents covered by the insurance. I will return briefly later to the use of fault as a decision-making guide.) These insurance costs are, in effect, the cost of eliminating catastrophic risks from the investors. They are allowable for rate purposes because the elimination of such catastrophic risks permits a lower rate of return to investors, and hence ultimately benefits the ratepayers. Whenever costs can be reduced through insurance or other forms of risk spreading, a failure to permit that spreading (or an inducement to avoid spreading, as would occur if insurance costs were not recoverable through rates) would result in imposing an unnecessary <u>cost</u> on ratepayers -- the cost of inducing investors to take a risk of catastrophic loss.

It is my understanding that in the case of fossil plants, this risk spreading approach is essentially effective in covering the entire risk. Clean up and repair costs can be fully insured; or if not, they are reflected, perhaps on some normalized basis, in rates. Replacement power costs are insured to some degree and, if not, are recovered through rates. (It is worth noting, though, the cost of replacing fossil-fueled energy from other fossil-fueled sources is not as dramatic as purchasing fossil-fueled energy to replace nuclear-fueled energy.) Given the lengths of the outages involved, and the lower capital investment per kW required for fossil facilities, capital costs are either recovered from ratepayers during the outage or, if a rate base exclusion does occur, the impact on investors is not so catastrophic as to be inconsistent with the risks for which they are compensated through the return on investment.

The nuclear accident rate case presents the question, as did the TMI proceeding, as to the proper treatment of nuclear accident costs which were either uninsured, or were not fully insured. Allocating a major portion of such costs to ratepayers, at least in situations where the resulting rates cannot be regarded as catastrophically burdensome, mimics as closely as possible the effect of insurance and loss spreading. The burden of the actual accident as reflected in electric rates would be spread out over a long period of time and no single user would bear a sudden huge cost.

In this way, the risk of nuclear accident costs -- however rare -- would have been reflected in the cost of nuclear energy, and in a way which required no one to take catastrophic risks of huge uncompensated losses. Refusing to allow recovery of such costs through rates would be analogous either (a) to forbidding electric companies from buying insurance against accidents, or (b) excluding the costs of such accident insurance from rates. Under those conditions, the investors -- barred from spreading the risk -- would face the possibility of catastrophic losses as a result of accidents. They would either not invest or would invest only if the rate of return available were sufficiently high to justify taking a serious risk of being wiped out if an accident occurred.

The effect of allocating accident costs to ratepayers as a risk spreading surrogate for insurance stands in striking contrast to the effect upon capital costs of allocating such accident costs to investors. The very real and inescapable constraints of the capital markets -- the freest of all marketplaces -- will transform the apparent decision to impose the accident cost burden on the investor into something very different. Investment in a utility which faces the possibility that a billion dollar investment may suddenly and irretrievably be lost posits a risk radically different from investment in a utility where the opportunity exists to earn a return on all investment prudently made. That dramatically higher risk will require that utility investment capital be drawn from sources looking for a classically "entrepreneurial" opportunity and its attendant substantially higher return. Moreover, that higher capital cost would have to be borne by ratepayers of all nuclear generating utilities since investors will not know which firm might actually incur the loss and which will escape it.

Given the cautious nature of utility investors -- their risk aversion relative to investors as a whole has always been high -- that required rate of return would be much higher than utilities now experience. Such a high -- but necessary -- return on investment would inevitably hurt ratepayers as a class far more than inclusion of the major part of accident costs in rates. Moreover, it could artificially and dramatically raise the cost of nuclear power in comparison with fossil power.

A still higher user burden, and misallocation between nuclear and fossil fuels, would come about if investors and their management refused to take the risk of investment in nuclear capacity, either because the requisite high return was not permitted or because there was uncertainty whether it would be. Then no choice between fossil and nuclear would be available, regardless of how inefficient fossil fuels might be. Ratepayers would be left bearing unnecessarily high fuel rates.

Indeed, this is the result most likely to occur in the real world. While pure economic theory might indicate that the perceived higher risk would be translated into continued investment in nuclear capacity, albeit at a higher capital cost, corporate reality indicates that utility management faced with the uncertainty of rate of return recognition of the increased risk, might simply abandon the nuclear option.

Nor are these observations mere theoretical speculation. Anyone following developments in the nuclear industry since the TMI accident can readily discern two trends: a marked reduction in the commitment to nuclear power and an increase in capital costs for nuclear generating utilities. Examples abound, but let me cite a few just since the beginning of this year. The Haven plant in Wisconsin has been cancelled due to regulatory and financial uncertainties. Also citing regulatory uncertainties, Capco has cancelled four units: Erie 1 and 2 and Davis-Besse 3 and 4. New England Electric has cancelled its Charlestown, Rhode Island, plant. Detroit Edison has dropped its Greenwood 2 and 3 units. Duke's Cherokee 3 unit is delayed indefinitely.

On the issue of capital costs, an article on p. 10 of the March 20, 1980 issue of Nucleonics Week, discussing financing problems faced by Duke Power, a major nuclear generating utility, observed that "the market's perception since Three Mile Island says there is an additional risk with nuclear. It's not a tremendous differential but it's there." That assessment preceded the Pennsylvania Commission's May 9 decision in the GPU case. Not surprisingly, the Washington Post's front page coverage of that decision featured the observations of a financial analyst that investors are not stupid and would see that decision as increasing the investment risk of nuclear generating utilities. I cannot provide you with any detailed financial analysis to demonstrate the effect of that decision on the market in the last two weeks but both the observation and the prominence it was given in the Washington Post are of interest and concern.

While on the subject of the May 9 Pennsylvania order, let me describe briefly what it decided. The Commission removed the cloud over Met Ed's continued viability created by its November 1, 1979 order to show cause that its certificate of public convenience and necessity should not be revoked. The Commission ruled that no such revocation was justified. However, it removed TMI-1 from the rate base because, although the plant is operable, GPU has been blocked from using it by NRC proceedings. Finally, the Commission permitted recovery of the cost of energy to replace that produced by the TMI units. In this connection, the Commission also provided for recovery of certain deferred energy costs and for capacity charges associated with replacement power.

In my view, the Commission's treatment of replacement power costs was fully justified. It would have been the grossest form of misallocation to exclude from rates that portion of replacement power costs which represent the fact that such replacement power costs more to produce than nuclear power from TMI. These are not costs of power which arose because TMI was built nor were they created by the fact that a nuclear accident occurred. Had TMI not been built, this portion of the replacement power costs would have been reflected in the rates paid by consumers, and would have represented the normal cost of electric power to ratepayers. By building TMI, Met-Ed attempted to furnish ratepayers with cheaper electricity than would have been available from other sources. The accident prevented it from doing so. Assigning this element of replacement costs to the ratepayers would therefore simply re-establish the situation which would have existed had the nuclear alternative not been tried.

A decision to exclude this portion of the replacement costs from rates would destroy all incentives for power companies to try to devise ways of furnishing cheaper electricity. Such a decision would mean that an attempt to furnish cheaper electricity, whether it succeeds or not, results in the inability to recover "ordinary" power costs through rates. Success in the attempt would benefit users (as it should) and would give no special benefit to the investors; failure would still benefit the users and severely damage the investors. It is apparent that under such circumstances it would be insane for any investor to make any attempt to provide cheaper power. Yet only through such attempts can one hope to allocate resources for energy production efficiently, *i.e.*, only thus can one develop cheaper forms of electric power and thereby provide the ratepayers with lower electricity costs.

Further, the Pennsylvania Commission rightly did not seek to disallow that additional portion of replacement power costs which reflects the fact that such power had to be bought on an emergency basis after the accident. Such costs should be allocated like any other nuclear accident costs; *i.e.*, as I discussed earlier, they should, for the most part, be included in rates. Indeed, given the Commission's treatment of the capital and fixed O&M costs of TMI, their entire inclusion in rates is fully justified.

It is the Commission's treatment of those capital costs and fixed O&M costs for TMI-1 and, while not directly involved in the May 9, 1980 decision, for TMI-2, which raises the most serious questions. Relying entirely upon a narrowly focussed discussion of whether TMI-1 is presently used and useful, and discussing the prospects for its imminent return to service, the Commission concludes that TMI-1 must be removed from rate base, eliminating revenues of $26.9 million from the rates of Met Ed (about 7.25% of the revenues produced by base rates and 23% of the dollars allowed as return) and $11.7 million from the rates of Penelec (about 2.5% of the revenues produced by base rates).*/ As my earlier discussion indicated, I would quarrel both with the result and with the Commission's analysis and discussion leading to that result.

Taking up the analysis first, the Commission confined its discussion to the literal meaning of the phrase "used and useful". Although it acknowledged that this standard "is a flexible rate making tool whose definition to some extent is shaped by the individual circumstances of each case",**/ it made no attempt to view the standard in terms of risk allocation. Rather, it confined its discussion to the plant's past utility and the imminence of its prospects for future service. I believe that a broader view was called for by a fundamental understanding of the issues involved and would have been sustained on judicial review if properly articulated.

As to the result, I would have hoped that the Commission would have at least indicated a basis for sharing these capital costs between investor and ratepayer. Let me be clear as to my views on this point since I did not address it in detail earlier. I would not advocate imposing the entire cost burden of an accident upon the ratepayer. Rather, I would share it between ratepayer and investor, with the ratepayer bearing a major portion.

First, because I regard that result as a surrogate for risk spreading through insurance, it is germane that insurance rates vary by individual on the basis of accident histories. The extra insurance premium borne by a company with a particularly bad accident record could properly -- on a risk allocating theory -- be excluded from rates.

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*/ Pennylvania PUC v. Metropolitan Edison Co., 28 PUR 4th 555, 586 (Pa. PUR 1979); Pennsylvania PUC v. Pennsylvania Electric Co., 28 PUR 4th 209, 229 (Pa. PUC 1979).

**/ Pennsylvania PUC v. Metropolitan Edison Co. and Pennsylvania Electric Co., Docket No. I79040308, Order dated May 9, 1980, slip opinion at 15.

This treatment, like other items excluded from rates by traditional precedent, would serve to lessen somewhat the return to investors in companies experiencing an accident rate higher than the norm without substantially raising the risk to utility investors across the industry. The result would be to create incentives for greater individual firm safety, without permitting crushing burdens which would artificially raise the risk of investing -- and hence the costs -- in the industry as a whole.

It can be argued that such an economic incentive is not essential in the electric industry where a set of specific incentives and deterrents is already in place. First, there is a pervasive scheme of regulatory oversight, currently being re-examined and, it can reasonably be expected, improved because of insights provided by TMI. That scheme involves the prospect of substantial fines and penalties which the agency is now applying more vigorously as illustrated by the $450,000 fine recently imposed on a utility in the Midwest. Second, there is the incentive provided by regulatory uncertainty, both as to the precise allocation of costs between ratepayer and investor in a given accident, and as to the prospects for future licensing should an accident occur. Third, there is the considerable incentive asserted through peer pressure and the protection of corporate and personal reputation.

Nonetheless, doubts concerning the complete effectiveness of such controls suggest that an economic incentive should be maintained by imposing some of the cost of accidents on the investor. But the amount so allocated should not exceed what would be a reasonable insurance deductible. It should not be of a size such that investor risk across the industry would be substantially increased. For, if it were, only relatively small efficiencies would be gained (as a result of further inducements for safety within the firm) and these would be achieved only at the cost of creating very large inefficiencies (as a result of unnecessarily high investor risk across the whole industry).

As a measure of that deductible, I suggested in my testimony that the companies could be permitted to recover the sum of (a) the operating costs of both TMI units, (b) the capital costs associated with the debt and preferred stock elements of the capital invested in both units, and (c) a portion of the return on equity. That is, I would eliminate from the return that portion which corresponds to the level of operating risk for which the investor was being compensated, but I would not eliminate the entire return because the investor was not being compensated for a catastrophic loss of the entire investment. One way of measuring the amount of return which should be eliminated might be to consider the extent to which the allowable rate base should be reduced to reflect an appropriate "insurance deductible". The allowance of recovery of some capital costs during an extended outage is consistent with the approach which has been adopted prospectively by the Federal Energy Regulatory Commission for outages affecting projects like the Alaskan Natural Gas Pipeline and certain LNG import facilities.

The Commission failed to address such a sharing of costs, while expressing confidence that its decision provided Met Ed with revenues sufficient for its survival. I am concerned equally with the long-term validity of that conclusion and with the possibility that the allocation of substantial elements of risk to investors, beyond those for which they have been compensated in the return allowance, will eventually impose even greater costs upon ratepayers who will have to provide the return demanded in the marketplace in order to attract capital to this enterprise.

Let me turn for a moment from the Pennsylvania decision to related developments on a broader front. Despite an impregnable case, at least in my judgment, for allocating replacement power costs to the ratepayer, there are indications that a different view prevails in some quarters. A bill introduced in the California legislature would block the pass through of such costs associated with shutdown of a nuclear unit. A ruling by the Commerce Commission here in Iowa, involving Iowa Electric Light & Power, disallowed certain replacement power costs associated with a nuclear outage, because the outage was partially due to management negligence. On the other hand, the Arkansas PSC modified the fuel adjustment clause of Arkansas Power & Light to provide for a greater pass through of replacement power costs associated with nuclear accidents. Press reports indicate that the change was made in order to preserve an incentive for reliance on nuclear power.

On a variety of fronts, there have been indications that management fault should be a decision-controlling factor in the ratemaking treatment of nuclear accidents. Both the New Jersey and Pennsylvania Commissions have indicated an interest in such factors in connection with TMI. As I indicated a moment ago, the Iowa Commission relied on fault considerations in disallowing certain replacement power costs.

I can fully understand the tendency to consider such factors. Fault has been a controlling factor in liability determinations for centuries. It is ingrained in our notions of fairness. However, the more I have considered it, the more it seems a fruitless path in the context of ratemaking decisions involving nuclear accidents.

First, because the machines and processes, and their management, are so complex, I am convinced that there will never be a nuclear accident in which a lack of "fault" by utility management will be indisputable. Hence, this approach is not a guide to choice but a one-way path to assigning risks and attendant costs to the investors. Second, and more important, taking this approach ignores the economic reality in the ratemaking context that assigning the risk and attendant costs to the investor, even if that decision is based on fault considerations, will simply increase the risk faced by the investor and the attendant cost of capital, shifting the cost eventually back to the ratepayer. Hence, it seems to me a pointless endeavor to undertake a determination on fault as a guide to a decision on rates.

Returning to the decision of the Pennsylvania Commission, in saying that I disagree with the result they reached, I do not by any means intend to indicate that I am unsympathetic to the extraordinarily difficult task they faced. Before TMI, our reliance on nuclear power was based on value judgments concerning the acceptability of certain risks to society in view of the benefits provided to society by this form of energy. While our political process had produced a judgment that the benefits outweigh the risks, that judgment had not been accepted by an increasingly vocal minority. The TMI accident called into question the assumptions underlying those earlier societal determinations, and set in motion a fundamental re-examination of our earlier conclusions. Thusfar, that process of re-examination has produced a re-affirmation of the decision to rely on nuclear power. Nonetheless, those concerned about the fundamental commitment became even more vocal and were joined, particularly in the area directly affected by the accident, by a previously uncommitted or uninvolved contingent.

Inevitably, the Commission finds itself thrust into the midst of these broad concerns as it copes with the accident's ratemaking consequences. Yet, it had little if anything to say about the fundamental judgments which led to the growth of nuclear power. And it can do little to marshal the full resources of our society, or even of the nuclear industry, to cushion the impact of the accident upon those directly affected. In its May 9 decision, the Commission very wisely and justifiably expressed its dissatisfaction with the lack of a Federal response to the Commission's calls for assistance in dealing with the accident's financial consequences.

Lacking such response, the Commission can choose only between investors and ratepayers in allocating the accident's burdens. That choice involves an inevitable element of value judgment on the desirability of nuclear power. At least, the choice is vested with that aura by those whom it affects directly. When a regulatory agency is called upon to make, or is perceived as making, such value judgments on risk/benefit evaluations, it may be seen as moving beyond its usual sphere of responsibility for deciding questions on the basis of an evidentiary record to which it applies established legal standards.*/ In such circumstances, there is an uncomfortable realization that such value judgments are better made, not through the regulatory administrative process, but through the political process.

I would suggest that the appropriate response to such concerns in the context of ratemaking treatment of nuclear accidents is to accept the judgment of our society, reached through the

*/ See Cooper, The Role of Regulatory Agencies in Risk-Benefit Decision-Making, 33 Food Drug Cosmetic Law Journal 755 (1978) for an interesting discussion of this problem.

political process, and reaffirmed since TMI, that the benefits of nuclear power outweigh its risks. Hence, the rate decision should be made with a full awareness of its economic consequences for nuclear power and should not be used, either consciously or unconsciously, as a means of altering that judgment concerning nuclear power. The best means to accomplish this result is a shared allocation of the accident risk along the lines I have described.

I said in my original paper on this subject last Fall, and I say again, that I do not envy those commissioners who must face and decide these difficult issues. Because the stakes are so high for all of us, though, I hope that my own observations will assist in reaching a result which most benefits our society and our nation.

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FINANCIAL AND RATE - MAKING ASPECTS OF THREE MILE ISLAND

Gordon R. Corey
V.C. (Ret.)
Commonwealth Edison Company

The financial and rate-making implications of T.M.I. can be discussed in three ways --

(i) from the viewpoint of General Public Utilities Company and its customers;

(ii) From that of the electric power industry as a whole, and

(iii) with respect to its effect upon the entire nuclear industry.

Early in May of last year, I appeared on a panel at a European Nuclear Conference in Hamburg dealing with the significance of Three Mile Island.[1] Dr. Milton Levenson was lead-off man on that panel. Just before we left, Milt gave me a present, a sweat shirt he had picked up in Harrisburg showing a reactor fanning itself, with the caption -- "Happiness is a cool reactor."

That sweat shirt was a good sign -- as was also the offering of "cheeseburger meltdowns" at a Harrisburg lunch counter. When we have learned to accept nuclear technology -- to treat it with care and respect. but also to laugh at it -- when we have done that, then there is some chance that we can eventually learn to live with it and exploit its enormous benefits.

Recently, there have been other good signs. For example, I have been impressed by comments of both the New Jersey and Pennsylvania regulatory commissions recognizing the need -- the real need -- to get T.M.I. Unit One going again.

In its May 9, 1980, order, the Pennsylvania Commission mentioned T.M.I. One's excellent operating record. And here is what the New Jersey Board of Utilities Commissioners said in their April 1, 1980, Jersey Central order:

> "It shall be noted that if and when T.M.I. One is returned to service, the Board will expeditiously return the unit to rate base. . . . The Board has urged the NRC to allow the restart of T.M.I. One as long as public health and safety aspects of the restart were resolved satisfactorily. The State of Pennsylvania has similarly argued that economic consequences of potential delay are contrary to the public interest. We again urge the NRC to recognize the economic and service consequences of further slippage in commencing the restart docket."

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1. Copies of my notes may be obtained by writing me at P.O. Box 767, Chicago, IL 60690.

I. FINANCIAL CONSEQUENCES FOR GPU

None-the-less, the financial effect of the accident on GPU has been very bad. As the N.J. Board of Public Utilities Commissioners recently said in docket 795-427: -

> "... the Board has recognized the dire financial condition of this utility (Jersey Central) resulting in its inability to finance required construction through traditional capital markets...."

And elsewhere: -

> "All parties have agreed that JCP & L cannot presently sell long-term debt or preferred stock and that GPU cannot sell common stock given the financial condition of the respective markets."

> These statements were made just six weeks ago, after Moody's had again down-graded Jersey Central's senior debt -- this time from Baa to Ba. Yesterday, GPU common stock closed at 6¼ -- and I shudder to think where it would be if a large several-million-share block of new-issue stock were brought to market.

* * * * *

Events of the Past Year

(1) In May of last year, a small EEI task force was formed to consider the financial implications of TMI.

(2) At that group's May 18, 1979 meeting, GPU confirmed that additional purchased power costs resulting from the unavailability of the two TMI units amounted to $23 million a month. While somewhat improved power purchase arrangements have been negotiated since then, oil prices have also increased. I suspect, therefore, that the $23 million a month or $276 million a year of added costs may be on the low side today. However, if TMI One could be returned to service, the added costs (whatever they are) could probably be reduced by about 60%.

(3) At our May 18, 1979 meeting, a Citibank representative discussed plans for extending a $400 to $500 million revolving credit arrangement. Subsequently, significant bank credits were established. Recently, however, some banks have hesitated to extend further credit without a pledge of accounts receivable or favorable regulatory action.

(4) Since then, there have been several rate increase approvals:

- On April 1, 1980, by New Jersey,
- On May 9, 1980, by Pennsylvania,
- Again on May 13, 1980, by New Jersey.

As a result of last week's $60 million annual rate increase by New Jersey and an assurance of an annual increase on the order of $72 million the week before in Pennsylvania, Jersey Central's bank credit has been increased modestly, from $110 to $137 million.

(5) The whole situation is difficult to evaluate, but the New Jersey board was probably right in concluding that GPU's financial situation is downright serious.

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The financial and general management problems presented to GPU by the TMI accident have been extremely difficult. I know the personal anguish that the GPU executives have suffered, the worries, the public criticisms, the regulatory frustrations and the hard financial questions. While their efforts to secure bank financing have achieved a degree of success, due in part to the cooperation of the New Jersey and Pennsylvania regulators, things are not out of the woods yet. In a sense, they may never be. We may find that TMI was just one more development in a spreading quagmire of social change which is making it difficult for the entire investor-owned sector of our industry to build generating plants. The ultimate result may be that our needed future generating capacity additions must be financed in the public sector -- through higher taxes, tax-exempt borrowings or government guarantees. While this may not be a disaster, it will be further proof that the public often find it more palatable to finance needed capital investments through taxes or inflation than through use charges. Toll roads and bridges have never been popular. And societies which are short of capital seem always to shy away from financing their capital-intensive energy supply industries in the private sector. It is no accident that most electric utility systems in our western democracies are government owned -- the principal exceptions outside the U.S. being the large investor-owned systems in Japan, the RWE system serving the Ruhr valley of Germany and Iberduero, the mixed private-public electric system in Spain.

In any event, it seems almost certain that it will be some time before the GPU system will regain the ability to enter the capital markets freely and again readily finance large generating station expansion programs as they did in the past.

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However, it does little good for us here to speculate about whether, and how soon, GPU will get out of the woods. So let us turn to my second subject: -

II. FINANCIAL IMPLICATIONS FOR THE U.S. ELECTRIC POWER INDUSTRY AS A WHOLE

(a) Early Rescue Attempts

At the May 24 meeting of our EEI task force, referred to earlier, we decided not to recommend a massive financial aid plan, with capital funds or credit guarantees to be provided by the rest of the electric power industry, because we felt that such a plan would escalate the discussion of Three Mile Island through regulatory hearings throughout the country with an ultimate possibility of encountering a contagious denial which would be counter-productive.

I believe this decision, painful though it was, to have been a correct one. However, the need to mitigate the financial consequences of future occurrences similar to TMI was recognized. Accordingly, our industry has gone ahead to organize a mutual insurance company which will ensure against the higher replacement power costs which might result from an unexpected and prolonged shutdown of a large nuclear generating unit. This and other steps discussed below comprise a series of important developments resulting from the Three Mile Island accident.

(b) New Institutional Arrangements

These have taken the form of the new insurance entity, Nuclear Electric Insurance Ltd. or NEIL, as well as two other entities: N-SAC, the Nuclear Safety Analyses Center, and INPO, the Institute for Nuclear Power Operation.

(i) New Insurance Entity. NEIL is an acronym for the new offshore insurance pool which has been established to insure a significant portion of the extra power costs resulting from a nuclear accident.[2] The pool will not insure the entire amount of such extra costs because that would be a bad insurance principle -- also because it would be too costly; we simply cannot afford to provide this much coverage at the outset.

The coverage provided by NEIL will not start for 26 weeks following the onset of an outage. After that, insurance recoveries will not exceed $2 million per reactor-week for 52 weeks and half that much for another 52 weeks, thus resulting in a maximum recovery of $156 million for a single reactor. Even with these limitations, the premium cost will be high, approximately $1½ million per reactor-year.

So far, we have received almost enough commitments to make the new insurance entity viable. As soon as a few more regulatory approvals are obtained, possibly within the next month we will be able to go forward. Thus, it is expected that insurance policies written by NEIL will be in effect by August 1 of this year or soon thereafter.

Why an off-shore company? The answer is simple. Because the insurance laws of most states were not designed for insurance pooling arrangements where the principle assets are binding commitments by financially responsible insured institutions to ante up specified amount of money in the event of a major loss by a member of the group.

Most insurance laws are designed to protect small policyholders from fly-by-night insurers. Consequently, they require that insurance firms establish and segregate large cash reserves to guarantee payment in case of loss. Normally, the size of these reserves is established as a multiple of the largest possible loss. For NEIL, these laws would

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2. The insurance protection offered by NEIL is somewhat akin to the "use and occupancy" insurance offered for commercial buildings and manufacturing plants. It is in addition to the public liability and property damage insurance which have been available to the nuclear industry for years through private insurance company contracts, a property damage insurance pool (NML) and Price-Anderson liability insurance.

require the set-aside of billions of dollars in largely unproductive reserves. Hence, the need to go off-shore, to jurisdictions like Bermuda, where insurance laws have been designed to permit the kind of self-insurance pool which best fits the nuclear insurance need.

(ii) Other Institutions -- N-SAC and INPO. These are already-established institutions. They are operating and operating well.

N-SAC produced the first full-scale in-depth evaluation of the Three Mile Island accident. Recently, on-site INPO inspections and evaluations have commenced. The inspectors and evaluators are competent. They have conducted detailed inspections in depth and made constructive suggestions.

(iii) The Regulatory Aftermath of T.M.I. The new regulatory requirements growing out of the accident at Harrisburg are bound to be costly: -

(a) We at Commonwealth Edison have already committed about $5 million per unit for post-T.M.I. modifications such as reactor head vents on our PWR's at a total cost of $60 million to improve safety. These modifications will meet the NRC's 1979-80 requirements.

(b) We have budgeted $50 million per unit for a total $600 million for anticipated additional back-fitting changes for the next five years. These include plant-specific control room simulators, off-site emergency centers, post-accident monitoring systems and improved plant computers.

(c) In addition, the inevitable delays in bringing such plants as Diablo Canyon, Sequoyah, Salem and North Anna on the line, which have resulted at least in part from T.M.I., and the slow-up in construction and licensing of those nuclear units still under-way, is resulting in construction cost, escalation and other costs, including added carrying charges and replacement power costs during the prolonged waiting period prior to licensing. Taken all together, the cost of these factors may equal or exceed $200 million per unit -- significantly more than the related back-fitting costs.

(d) Nevertheless, we expect nuclear power will continue to show a significant economic advantage over coal or oil.[3]

Costly or not, the overall thrust of the new regulations will be constructive. Hopefully they will help restore public confidence in nuclear power and the morale of those working to make our nuclear plants reliable, efficient and safe -- neither of which are trivial matters.

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3. Last, (1979), Commonwealth Edison's bus-bar savings from nuclear generation were $370 million compared with coal and $865 million compared with oil. In 1979, our 25 billion kilowatthours of nuclear generation replaced either 14 million tons of coal or 45 million barrels of oil or some combination of the two.

However, we must take care that the new procedural changes resulting from T.M.I. do not contribute to technical rigidity which could destroy the nuclear option. Now, more than ever before perhaps, our capability for self-examination and improvement is needed. But this capability can be lost if regulatory requirements are imposed with paranoic inflexibility.

It is widely believed that at least some of the difficulties at T.M.I. arose from a preoccupation with detailed procedural regulations which blinded both regulators and operators to areas where safety measures could be imposed -- and to the need for wisdom and open-mindedness. While it seems clear that regulatory practices need overhauling, the continued improvement in operational safety requires increased imagination and flexibility on the part of both operators and regulators, a readiness to accept changes for the better, and less emphasis upon procedural requirements (such as logging the locking or unlocking of an access door) which are largely unrelated to station operation but which by their unrelenting inflexibility may detract from the very safety they were intended to enhance.

(iv) Effect on Credit of Electric Utilities Having a Strong Nuclear Commitment

Several times during 1979, we examined the credit ratings, bond yields and stock prices for an array of large electric utilities to try to determine whether or not T.M.I. had adversely affected those like CEOo with a strong nuclear committment. It appeared that this had not been the case. Recently, however, there is some evidence that the debt securities of firms with a large investment in nuclear generation may be suffering a modest disadvantage in the long-term bond market.[4] This disadvantage may be only temporary. Indeed, it may disappear completely after NEIL begins to write nuclear insurance policies.

Now let me turn to a fifth aspect of the implications of the Three Mile Island accident upon our industry, namely -

(v) Changing Perceptions as to How Risk Should be Handled in Utility Rate-Making

It is paradoxical that the very savings which nuclear power is providing today are the source of concern over the financial consequences of a nuclear accident.

Rate increases are always distasteful, but when they are sharp rather than gradual -- and when they can be attributed to a single regrettable accident -- they are particularly unacceptable. No matter that electric rates payable by GPU customers would have been as high or higher all along had it not been for nuclear power, the sudden withdrawal of its benefits was distasteful -- and the withdrawal symptoms have produced financial agony for the supplying utility.

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4. See Charles Benore, "A Survey of Investor Attitudes Toward The Electric Power Industry", Paine Webber/Mitchell Hutchins Inc., issued subsequent to this talk, June 18, 1980.

An article by William Shipman in the May 14, 1979 issue of the New York Times, was entitled, "When a Nuclear Plant Shuts, Consumer Pay". In that article, Dr. Shipman concluded that "we can be pretty certain" that utility customers rather than stockholders will pay the cost of more expensive energy when a nuclear plant shuts down. His apparent conclusion was that this is unfair. Although a wide spectrum of electric utility equities are selling well below book value, he suggested that utility stockholders are adequately compensated for risk. All investors (he observed) have been doing rather poorly in recent years.

But this is no longer a question of fairness. Today it is a question of whether or not we will build any more nuclear plants -- or enough coal-fired plants for that matter. New capital funds cannot be conscripted -- at least not in U.S. money markets -- not yet. And private investors are simply not going to provide the money needed to fund risky capital-intensive ventures if all of the resulting benefits are flowed through to customers while investors are asked to bear all the risks.

A possible answer to this dilemma is full-risk insurance, provided the insurance premiums are allowed for rate-making. We have already taken a modest step in this direction with NEIL.

Another answer however must be the ultimate recognition that there is no free lunch. If customers are to receive the full benefits of a new technology then they must bear a significant portion of the risk as well -- for all new technologies do have significant risks. If customers are asked to shoulder none of the risks -- or only a part, as has been suggested -- then they are entitled to none of the benefits, or only a part.

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Turning to the matter of how local regulators faced up to the risks at T.M.I., it seems to me that the New Jersey and Pennsylvania commissions have faced up to a portion of the problem quite bravely. They have allowed the cost of replacement power to be passed on in higher rates, as indeed it should be. However, they have failed to provide for any rate recovery of the T.M.I. station investment itself. So far, this question has been pretty much brushed under the rug. However, it must ultimately be resolved. If its resolution fails to allow full recovery of that investment, through revenues, the outlook for further nuclear power or other technological development in the electric power supply areas is dim.

Today, the view to the future is uncertain. State regulators are not in clear agreement on this matter of risk. Thus, we are faced with a situation like the Lady and the Tiger. If, in the final analysis, it is decided that customers should receive all the benefits but bear little if any of the risks of a new technology, I assure you there will be no more nuclear plants built in this country, and few if any solar or synfuel or wind or geothermal installations for that matter, except as paid for with federal funds.

III. LONG-RUN IMPLICATIONS FOR U.S. SOCIETY AS A WHOLE

Last year, Commonwealth Edison Company generated approximately 25 billion kilowatthours with nuclear power. A few years from now, our annual nuclear generation will have risen to 60 billion kilowatthours.

For the U.S. as a whole, today's nuclear generation is about 300 billion kilowatthours and by 1990, unless new plants are unduly held up, it will reach one trillion kilowatthours.

How much power is this? One trillion kilowatthours is equivalent to approximately one trillion pounds of coal -- or 500 million tons. It is also equivalent to over one and one-half billion barrels of oil -- over four million barrels a day. That is a lot of coal or oil.

Roughly one-third of our future nuclear generation will, in my opinion, displace oil -- about half a billion barrels a year by 1990, if we are allowed to complete and operate the nuclear units which are now underway. The rest of our nuclear generation will probably displace coal, which will still be needed in sharply larger quantities than today.

Moreover, if we were allowed to go forward and generate the maximum quantity of electrical energy with nuclear today -- if those plants which are virtually complete were licensed and allowed to operate at full capacity, and if utilities were encouraged to wheel their nuclear output around the country in order to achieve the maximum practicable displacement of oil at nights and on weekends -- then we could reduce the total U.S. use of oil for electric generation by 50 to 100 million barrels a year.[5]

I sincerely hope that the regulatory implications of T.M.I. do not suggest that this will be impossible.

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IN SUMMARY, MY COLLEAGUES AND I BELIEVE THAT THE ULTIMATE EFFECT OF THE THREE MILE ISLAND ACCIDENT WILL BE BENEFICIAL.

The immediate effect of the accident was to raise questions and slow down the development of nuclear power. Its secondary effect has been to stimulate a wide discussion of energy options. Its long-run effect may be to help us all address our energy supply problems objectively.

It took the incident at Pearl Harbor to force America into World War II. We may find T.M.I. to be the incident which forces us to face up to the hard choice of continuing to pursue the only available near-term energy options - coal and nuclear.

On the other hand, T.M.I. has brought clearly home the likelihood that a nuclear accident can put a firm's entire net worth at risk. This suggests that utility executives will hesitate before ordering additional nuclear plants in the future. Thus an alternative possibility is that T.M.I. will help bring about an indefinite prolongation of today's *de facto* moratorium on new nuclear orders.

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5. See attached memorandum dated May 20, 1980, for support of this statement.

This would speed the demise of the nuclear option. While man does not live by bread alone, he does very poorly without any bread. That goes for engineers, constructors, equipment suppliers -- and even for the over-weening crop of paper-shufflers who have come to depend upon prolonged nuclear licensing proceedings and EIS reviews for their livelihood. When the new orders stop, the infra-structure of small equipment suppliers and subcontractors and technical consultants will soon fall apart.

This was already beginning to happen to a limited degree before T.M.I. Now, the drop-outs appear to be accelerating. If we do not resolve the present stalemate soon, it will be too late.

MEMORANDUM OF POSSIBLE REDUCTION IN OIL USAGE OF RESTRICTIONS WERE REMOVED FROM NUCLEAR GENERATION

(1) Estimated additional generation on U.S. nuclear generating plants which already have operating licenses--and are generally operating today.

--For Commonwealth Edison Company, an analysis of the operation of its six large nuclear units which already have operating licenses indicates that the removal of NRC imposed operating restrictions and backfitting requirements, as well as cooling water discharge restrictions which limit the output of Quad Cities Station, would enable us to produce about three billion additional kilowatthours a year. This is about 10% of our total nuclear output. A similar increase of 10% in nuclear generation for the U.S. as a whole would be equivalent to approximately 30 billion kilowatthours a year. If all of this additional nuclear generation replaced oil, the reduction in oil usage would be nearly 55 million barrels a year. However, assuming that only about a third of the additional generation would replace oil, the oil savings would approach 18 million barrels a year.

(2) Effect of allowing those plants with "near term operating licenses" (NTOL's) to operate at full capacity

The NTOL's now include Sequoyah unit 1, a TVA unit located in Tennessee having a capacity of 1,148 megawatts; Salem 2, a New Jersey plant having a capacity of 1,115 megawatts, and North Anna 2, a Virginia plant having a capacity of 907 megawatts. If these plants were allowed to operate, promptly, at full capacity, they would produce approximately 17 billion kilowatthours a year at a 60% capacity factor. This would be equivalent to 30 million barrels of oil. Assuming that only the Salem output would displace oil, the savings would be equivalent to approximately 10 million barrels a year, continuing until the units would otherwise have been placed in service.

(3) Diablo Canyon

This is a two-unit plant owned by Pacific Gas and Electric Co. It is now being kept from operating because of earthquake concern. The plant has a capacity of 2,190 megawatts and is capable of producing over 11 billion kilowatthours a year, assuming a 60% capacity factor. This would be equivalent to 20 million barrels of oil a year, and its entire output would be expected to replace oil. Again, the savings from acceleration of the service date (or avoidance of further delays) would continue until whatever time it is assumed the station would otherwise have been placed in service.

(4) Three Units scheduled for completion in 1980

These units include the following:

Farley Unit 2, Alabama--829 megawatts
McGuire Unit 1, Duke Power--1,180 megawatts
La Salle Unit 1, Commonwealth Edison--1,080 megawatts

Total 3,089 megawatts.

These units are capable of producing approximately 16 billion kilowatthours a year at a 60% capacity factor. This is equivalent to nearly 30 million barrels of oil.

Acceleration of the service dates of these units by approximately a year (or avoidance of a year's delay in service date, which will be the likely effect of the existing de facto moratorium on licensing), would result in increased nuclear generation of approximately 16 billion kilowatthours, equivalent to a one shot savings in oil usage of approximately 30 million barrels, if all the nuclear generation replaced oil. If, as seems likely, only a third of the additional generation replaced oil, the one time savings would probably be on the order of 10 million barrels.

(5) Total possible oil displacement

(a) It appears likely that, at a minimum, the oil displacement resulting from the foregoing would exceed 50 million barrels during the first year.

(b) As time goes by, additional nuclear units could be brought on line faster than now scheduled. Thus, the total annual savings might be increased by 20 to 30 million barrels, to roughly 75 million barrels, assuming that, each year, between five and ten nuclear units of the 1,000 megawatt class could be accelerated. Actually, between ten and fifteen units are now scheduled to be placed in service in most years from 1980 and 1985.

(c) Under emergency and wartime conditions, it seems reasonable to expect that regulations could be adopted requiring the wheeling of nuclear generation from coal-rich areas to oil-using areas, at nights and on weekends, for nominal wheeling charges. If such regulations were invoked, it would probably not be feasible to achieve 100% displacement of oil by the added nuclear generation, which would be equivalent to 130 or 140 million barrels of oil displaced a year, but it is not unreasonable to assume we could get a reduction of at least 100 million barrels of oil a year, based upon the foregoing analysis.

SIXTH SESSION, Wednesday, May 21, 1:15 p.m.

Concurrent Session C-2

COMMUNICATIONS LEGISLATION

CHAIRMAN: H. A. Latimer, Vice President
Illinois Bell Telephone Company
Board of Directors, Iowa State Regulatory Conference

SPEAKERS: Henry Geller, Assistant Secretary for Communications and Information
National Telecommunications and Information
Department of Commerce

Robert P. Reuss, Chairman and Chief Executive Officer
Central Telephone and Utilities Corporation

THE COMMUNICATIONS ACT AMENDMENTS OF 1980 (H.R. 6121)

Henry Geller
Assistant Secretary for Communications and Information
National Telecommunications and Information Administration
Department of Commerce

If you look at transmission after World War I, all there was was wire pair. With the coming of World War II, you had coaxial cable. After World War II, there was microwave radio relay and later satellites. Now fiber optics are coming. As a result, today there is a great deal of actual and potential competition in transmission.

If you look at switching, again great changes have occurred since WW II. The electromechanical means is still dominant. But now everything is moving to computers. If you go into a modern telephone center, you are obviously just in a modern computer building. A computer can be used one moment for switching the next moment for other purposes and ought to be so used. That's efficient usage. If you have it in the hotel as a private branch exchange, one moment you can have it to switch the calls, the next moment to take care of managing the dirty linen and keeping track of the empty rooms. That's the prudent way to use it. And you can go on and on. What is happening here is that there is a convergence, obviously, of the communications and of the data processing.

Now once again that poses a problem for the policy makers because data processing is not regulated and data communications is. This necessarily forces you to go in one direction or the other. And I think the clear choice we would like to make is to go in the direction of no regulation. That's an easy choice to make. If you look at the data processing industry, all you have to do is ask yourself: Would it be where it is today if, every time it wanted to introduce a new product, it had to go to a federal agency and ask permission to do so? If its rate of return were regulated, would the U.S. data industry be dominant, or would it be behind? The answer very clearly is we don't want to move in the direction of regulating data processing. Therefore, once again you're driven toward having to do something about the present law. It is not geared for competition. It is geared for a slowly evolving monopoly, for regulating traditional basic service markets once dominated by AT&T for telephone, and Western Union for telegraph.

When you introduce competition, the Communications Act of 1934 becomes a burden. It is not geared to competition. For one thing, it says nothing about it. Under the law, the FCC cannot opt for competition wherever feasible. There is a Supreme Court case on point called "Three Circuits" (<u>FCC</u> v. <u>RCA</u>, 346U.S. 86 (1953)) which says that you have got to find <u>that</u> competition will bring positive benefits. You can't just say you're relying on it. So the Act does not fit what is actually happening as a result of rapid technological change. It causes all these new competitors to come in and get permission to compete, and here again it's just being wasteful.

There's a substantial cost for regulation. It drives up the cost of the service, it delays service, it inhibits innovation. If competition will work, competition is the best force for driving prices to marginal costs. The reason why you have regulation is to substitute for the marketplace. You need to have the government come in and say what is proper in the rate base, whether this investment is proper, and whether this return is reasonable as a substitute for competition.

But when you do have these competitive forces at work in so many areas, you have to ask what is the regulatory scheme about? What we have found is that people with their lawyers are still fighting very much before the Commission rather than with their products or services in the marketplace. There are long delays. Issues march from one proceeding to another and they go on forever. Jarndyce v. Jarndyce has nothing on FCC proceedings. The validity of the Telpak rates began in 1961 and, as most of you know, it is still in doubt. It probably will be remanded by the court of appeals and that may be a record. (On June 26, 1980, the court upheld the FCC in the latest round of Telpak appeals, but remanded some issues for further study.)

There was one radio case, KOB, that went on for about 25 years. I'm not sure that Telpak will beat that. But what I'm sure of is that it's time to end this reliance upon government, this fighting before the FCC. Economic rate regulation of all services is just not a valid approach today.

There is a joke I heard that came from somebody in the Bell System, honestly. The joke is that there are three dogs that have a delicious bone, and the bone is stolen by a fourth more vicious dog. The first dog is a preacher dog and he says, "Let us pray and the Lord will restore the bone." The second dog was a lawyer, my profession, and he said, "No, no, let us sue and we will recover the bone with triple damages." The third dog is a telephone industry dog and he said, "Let us whine, and the government will restore the bone."

I think, to its credit, that the telephone industry has changed and that attitude is passing. I think there is a consensus now, that competition is here to stay, so now let's get rid of government inhibitions on it. Let us really fight it out in the market. There is also a growing consensus that the worst of all possible worlds is half regulated-half deregulated, called "regulated competition." As I said, the 1934 Act does not recognize this competitive new environment. It thus has resulted in a series of false starts by the FCC. It's resulted a great deal in litigation. We are familiar again with the Execunet decision where the court of appeals actually made the law, instead of Congress or the Commission. And I think that's what we can look forward to, if we do not get legislation. We have this outmoded act, we have a Commission struggling and, to its credit, struggling very hard trying to figure out what to do. But it is running into the statutory prescriptions, and will have years and years of litigation. And that, in a nut shell, doesn't make a bit of sense.

This is a sea of change, or a watershed, to use an overworked term. When you have something of that nature come down the pike, Congress ought to lay down the ground rules. That's what the Congress is about. It ought to say there's been enough of a change, now we should legislate. Not crossing every "t" and dotting every "i," but saying here are the new principles, here are the new ground rules. And when Congress fails to do so, I think that's a bad reflection on it.

The Carter Administration has recognized that there is such a change. It recognizes that it is time to change the ground rules, rather than to let the Commission struggle and have the courts finally making decisions that belong with the Congress, because they involve policy--very, very important issues of policy. Just again, to digress, I think the Commission did very well in the Computer Inquiry II. My organization, NTIA, will be petitioning for reconsideration on certain aspects of it. There's no question that it's a step in the right direction. But there's no assurance at all that it will survive court tests. There are three very large issues involved. Can the Commission forebear from regulating; can the Commission preempt state regulation and deregulate customer premises equipment; and can the Commission construe the 1956 AT&T consent decree the way it did?

The Department of Justice is a party respondent. Five times Justice has said to the Commission, you are misconstruing the decree. You cannot take that phrase in the decree, "incidental to telecommunications" and construe it the way you are. The decree says that it must be a communication service whose rates are subject to regulation. We argued that the Commission can forebear from regulation, and still satisfy the decree. Justice has said "no" to that. Justice, as I say, will be a party respondent. If they confess error on the Commission, how will the case come out in the D.C. Court of Appeals? It will be years in any event before issues are resolved. Can you build an industry while you have this uncertainty? And then the decision could come out wrong, from our point of view, because we do believe in the direction the FCC is going. And if it comes out wrong, you're back to ground zero with an even bigger, fatter mess. That's no way to run a railroad. Since they are basic policy issues, Congress ought to address them rather than letting them go through years of litigation and entrusting to the vagaries of that litigation.

Thus, there is a clear need to enact new legislation. There is a clear feeling in the Congress that there is a need for it. There is also a consensus about a great deal of the legislation that has been introduced. There is a consensus that the law should now say that competition should be relied upon wherever feasible. I know I said to you that this came from technological change. But it's important for the law to recognize it. In so doing, the RCA case will be overruled and this standard will no longer be subject to a whim of the Commission. It will be a standard the Commission and the courts must follow. It's a standard the Commission should follow when it allocates spectrum. That's a very important part of the Commission's duty. For example, Xerox has come in proposing to set up its X-10 system and asked for spectrum. There ought to be a law which says that when you allocate spectrum, you ought to try to foster competition wherever feasible.

A second consensus is that once you get into competition, you ought to deregulate as much as you can, and move as fast as you can toward a marketplace. There is no sense at all in having economic regulation of MCI, of Southern Pacific, of the satellite carriers, or of SBS. They do not have market power. There is no reason at all to regulate resale carriers or sharers. They should be able to enter and leave markets and charge what they want. If the public doesn't like what they're charging, it can turn elsewhere. They have no dominance in the marketplace and, therefore, regulation serves no purpose other than to add costs, to chill innovation or, if you look at my profession, to make jobs for Washington lawyers. If you open up what is called "the Yellow Peril" in Washington, Telecommunications Reports, you will see every week the plethora of filings, one domsat carrier against another, one specialized carrier against another. It's not just the specialized carriers against AT&T, it endemic. And that should end as soon as possible.

The law, therefore, should call for deregulation wherever there is no market dominance or ability to raise or lower prices without affecting demand. Another area of consensus is that toll rates should fall entirely under federal regulation. The state toll regulation should be moved over to the FCC. The local jurisdiction should regulate only what you call either intra-exchange, or intra-district, or whatever word you want to use for local exchange service. And there are definitions in the bills now being considered for that. When you go between exchanges, the inter-exchange, the inter-district -- what we now call intrastate toll -- that should be under the jurisdiction of the FCC.

The system of separations and settlements, which is so important to our telecommunication system, is coming apart under competition. It moves large sums of money, in the neighborhood of $9 billion dollars every year, from interstate to intrastate. Some $5 billion of this is non-traffic sensitive. It is partly a subsidy. But nobody knows the exact amount of the subsidy. Some of that $5 billion is cost-justified. But it's still an arbitrary process. Separation is not by any means an exact science, and with the coming of competition that subsidy will be ending. It is necessary to cushion this transition. The legislation does that. It calls for all the carriers to pay an access fee. Then there would be a very small surcharge on that.

It would raise what we think is an amount close to $900 million. And that fund would be used for two purposes. First, to insure that local rates don't go through the roof in some rural areas, in Alaska, and in other places like that. Second, to insure that there is access from these sparsely populated places to the network without undue cost increases, because there will be rate de-averaging of inter-exchange rates. We think the amount of money to do this, based on our preliminary studies, is in the neighborhood of $900 million. The small surcharge will create a pool where monies can be transferred to maintain our national policy of universal service at reasonable rates. It will also insure access from Scabuse, Oregon -- or any other small town -- to the network at reasonable charges. Here again, if you don't act there is a problem because competition is coming. General Telephone, AT&T, and others have signaled that they will not continue the present system in the face of competition. So the only responsible thing to do is to have legislative action that does permit this transition cushion.

The most difficult part of the legislation is that part which deals with AT&T. The company does have a very large monopoly base. It can cross-subsidize off that base. The Commission has not dealt well at all with preventing that cross-subsidy. The Commission has sought to do it by trying to assign what are the "proper costs."

You're all familiar with its efforts in Docket 18128 and other FCC dockets. Accounting methods, while they're important and must be pursued, have not been successful. So in the new bill, the effort has been made not only to mandate accounting, which everybody agrees upon, but also to say that when AT&T is to compete -- in offering customer premises equipment, private line, advanced communications systems, data processing and so forth -- they should do so through a fully separated subsidiary. That subsidiary would obtain its facilities out in the open. To the extent that the facilities are obtained from the parent organization, such facilities would be available to everybody else. Such a system will prevent any possibility of cross-subsidy by AT&T. If it is going to make data transmission facilities available to its ACS subsidiary for example, it must make the same facilities available to competitors.

There are a number of provisions here. I won't go over them all because I don't have time, and I don't want to take you into the details of the legislation. But essentially, the method of dealing with cross-subsidies is a fully separated subsidiary and the required resale of the relevant services. There have been hang-ups on this because there are difficult issues in the transition about how do you deal with the R&D, Bell Labs, and manufacturing, when you have the regulated and the unregulated together in joint enterprises. They are being worked out; I'll return to that in a moment. But the hardest part of the bill has dealt with that. There is an agreement to overrule the consent decree, because it no longer makes sense. There is agreement to let Bell go in new fields. It does not make any sense where they face competition to say that there should be economic regulation of AT&T. If there is freedom here, it should be freedom for all. If we want to get the full benefits of competition, then we must permit Bell to compete. The entire telecommunications industry ought to be eventually let go. Any firm should be allowed to enter, to do what it wants, to take large risks, to earn whatever rate of return these new services yield, or to fall flat on its face, without calling upon regulated monopoly service ratepayers to make up any losses.

There are further provisions dealing with cable television and a number of other areas but, essentially, all the bills -- the Senate bills and the House bill -- have the skeletal structure I spoke about: competition where feasible, deregulate wherever feasible, handle separations through an access and surcharge system, overrule the consent decree, and provide during the transition for how AT&T shall compete in new services using its fully separated subsidiary. The real problems are in the transition and how long it will take. I'll not go into this any further because Mr. Reuss is going to talk about it. I would simply say that transitions are very sticky. They're very messy. I don't want to say that this will be easy at all. I think it will be very difficult. But what I would stress to you is that there really isn't any choice. We are in the soup. Once competition arose from technology, we were embarked on this road. And I repeat again, the question is whether we work out sensible, rational policies, or whether we just hack our way through years of litigation before the Commission and the courts.

That is why legislation is so desirable and why there is a consensus on this. As to its status, I think that there is a better than even chance that it will be passed in this Congress. I say that knowing that this is an election year and there aren't many working days left when you count them. I did once and it's frightening. Legislation must be out of the full House Commerce Committee by July 1. The Rules Committee in the House has said that it must be out by then. The people on the Hill have worked very hard on this -- particularly Chairman VanDeerlin, Congressman Broyhill, and Congressman Wirth. They have worked out an agreement on how to handle the AT&T transition with regard to information flows, R&D, and manufacturing. There are some fuzzy areas, but there are no longer basic differences on matters of principle. I think there will be a Subcommittee meeting called at the end of this month (May). That will be followed with a hiatus to allow the bill to be taken up by the full Committee and reported out by the July 1 deadline.

It is not by any means sure. The bill has been subject to the "perils of Pauline" and has been buried a number of times. But there is a consensus. There is a recognized need for legislation. If the bill isn't passed this year, everybody recognizes that they simply will have to return to it next year. It will not go away. The Senate has also worked very hard. Chairman Cannon has called for a bill and said that he wants to get one. Senator Hollings representing the Majority, and Senators Goldwater and Schmidt representing the Minority have worked diligently over the last few weeks. Using S.611 and S.622 as a base, they are working on a new bill. I think, again, that they have come very largely to agreement. Therefore, if the House bill moves, I think the Senate, in my opinion, will follow suit. That doesn't necessarily mean that there will be legislation. You still have the question of differences between the bills, the need for a House-Senate conference and not much time. And as I said, it's by no means sure. But it looks promising and if the legislation isn't the Telecommunications Act of 1980, it will be the Telecommunications Act of '81. There is just no avoiding this legislation. It would be derelict on the part of Congress to let those years of uncertainty and the court litigation proceed.

I think the theme I would stress is that we are on our way toward a marketplace solution and that we'll be a long time getting there. It will not be easy. Bell represents an enormous chunk of the industry. It still has great dominance when you look at the percentages. But the road we are taking is to more and more competition, more and more to the marketplace, more and more to get out of regulated competition, and to move it to a full marketplace solution. I think that we would like to get away from government management of U.S. telecommunications. There is no government that is as wise, I believe, as the marketplace would be.

One final anecdote: President Brezhnev, on May Day was reviewing the troops. Passing in review were enormous concentrations of missles, then of tanks, then the troops themselves, and finally at the end of eight hours there is a car that has in it three balding middle-aged men, smiling and waving to the crowd. Brezhnev turns to his defense minister and says, "What is that?" The defense minister replied, "Those are our economists. You'd be surprised how destructive they can be."

What I'm saying is that we believe in a marketplace solution here and not a Government "economic plan." My agency is part of the Department of Commerce. We believe in competition because the country needs to do all it can to improve productivity. That means it has to let telecommunications compete. Telecommunications is an enormous driving force in improving productivity where the U.S. is lagging. We want to fight inflation by reducing energy costs. Telecommunications can make a contribution here. We face very great problems both domestically and competing abroad in telecommunications information trade. It is important that U.S. industry be geared up to meet that fight. We are engaged in a number of trade endeavors, including those to remove non-tariff trade barriers, and the trans-border data flow issue. But I believe the most important thing we can do for U.S. industry on this issue of trade is to free that industry to compete in the marketplace without the fetters of administrative or economic regulation -- where you have to go and say, "Mother, may I enter?" -- and where you have to accept a limit on your rate of return.

Thank you.

INDUSTRY ISSUES IN THE TRANSITION TO THE COMMUNICATIONS ACT OF 1980 (H.R. 6121)

Robert P. Reuss
Chairman and Chief Executive Officer
Central Telephone & Utilities Corporation

I will speak to you today from two perspectives. First, as the manager of a telephone company that's concerned about retaining its present position in the marketplace, and second, as a member of the Telephone Industry Policy Council, a group that's been struggling for at least four years to try to bring about an industry consensus on legislation. During those years we've worked with Henry Geller, and I can say that Mr. Geller and his organization have done more to bring about a consensus between industry and government on this very difficult problem than any other group.

We started out four years ago with positions that were quite far apart. But I think that you will notice in my remarks today that the differences in our positions with respect to legislation and the impact of that legislation are surprisingly few. As was mentioned, the real villain in this piece is not the government. If there is to be a villain, technological change in telecommunications, as Henry mentioned, has been so rapid that the basic concept of a single monopoly distribution system is really no longer feasible. As a consequence, the common carrier principles on which our industry's structure is based are no longer tenable. At the same time, the industry feels, and it is a wide feeling, that the notion of some supplier of last resort should be available and that affordable telephone service should also be available to everyone. Second, the opportunity to exploit new technologies should be available to everyone, including regulated telephone companies. The problem is how to accommodate these two obvious yet apparently contradictory objectives. We don't feel that the solution should be left in the hands of an administrative agency, no matter how competent that agency may be. It must be decided by Congress after a thorough review of national objectives in the full consideration of the interests of all parties. So in our view, and I think this is a general industry consensus, communications legislation is necessary.

In the interim, it seems to me that there should be a strong initiative on the part of all companies at the state level to ensure that state regulators understand the magnitude of the telephone companies' problems. Companies must be given greater latitude to work out transition problems in a way that's fair to our customers and fair to our shareowners. Clearly each of the companies has significant capital recovery issues to deal with. Increased pricing flexibility, customer participation activities and depreciation rates should be actively pursued at the state level.

I think if there was ever any evidence that we needed legislation it was demonstrated by the FCC decision in Computer Inquiry II and the Intercity Access Charge Plan, Docket 78-72. Deregulation of terminal equipment and changes in the intercity market structure are inevitable. However, the real uncertainty is the transition mechanism, in particular the unrealistic time frame specified in the FCC order. We have tremendous capital recovery and revenue requirement problems. These have to be addressed promptly and realistically in the interest of everyone.

A major concern, of course, is the FCC's authority to deregulate terminal equipment. The preemption of state authority, as Henry mentioned, is apt to cause great consternation which could frustrate us as telephone companies as we try to move forward in a transition plan. Different attitudes prevail today among state commissions with respect to deregulation of terminal equipment. Yet this is something that represents over 20% of the total Independents' telephone rate base, somewhat higher than that in the Bell System. And over 25% of the total revenue requirement is based on terminal equipment and this must be dealt with intelligently. Of equal importance is the future of a technically and economically integrated telephone network. So we feel that there are still a number of questions to be raised even after the FCC decision.

The FCC has ordered, as Henry mentioned, a new access charge mechanism to be worked out by a joint board. And this could well be a step in the right direction. But, I think there is still some concern in the industry with respect to assuring a technically and economically integrated network. An issue related to this is the various telephone companies' roles as partners in the network. And a constant question is raised as to whether the various local telephone companies are partners in the intercity network or whether they are neutral exchange carriers.

The Bell System and the Independent companies have recently worked out plans for improvements in the long range planning process for the building and operation of the toll network. Tentative agreements for the joint ownership of toll facilities have been established. And these coordinated plans have long been sought by the Independent industry. But the question of whether we can continue as partners in the toll network is critical. Will the partnership only be for MTS and WATS services or will it also apply to certain enhanced services? Will it apply to services such as CCSA? With these questions, I think there is a reasonable uncertainty as to where some Independent companies might finally opt with respect to ownership. Will some of them decide to place investment in competitive intercity facilities or will they opt for a growing investment in the basic telecommunications network providing MTS and WATS?

Another question relates to the local distribution network. The pricing of the use of the local distribution network by intercity services has to be flexible enough to keep it competitive. Particularly, as systems such as cellular radio, XTEN and satellite provide alternatives to the use of that local network, its technological evolution in light of competitive influences must be carefully planned. Incidentally, this is an issue which has divided the telephone companies, particularly the rural companies with respect to the rest of the industry. It has to do with whether the Subscriber Plant Factor contribution and nationwide average rates should be frozen. I think the consensus of the industry position is that we require a system which makes the basic network competitive with alternative services.

Without going into detail, some of the factors that suggest the need for legislation, which Mr. Geller has related to, are (1) the unstable environment that can be created because of certain issues, such as the FCC's creative interpretation of the 1956 consent decree; (2) the FCC's authority under the Communications Act of 1934 to deregulate terminal equipment and competitive carriers' intercity services; (3) certain FCC-state jurisdictional issues; and (4) other impacts of the terminal equipment deregulation (for example, Commissioner Fogarty's separate statement which mentions that the detariffing of terminal equipment could raise serious questions for bond holders that in turn would cause legal issues to be raised).

Another concern is the FCC's ability to reimpose regulation. As Congressman VanDeerlin mentioned, "the commission continues to hold the possibility of regulation like a club over a rapidly changing industry". And, of course, I think another problem that's particularly bothersome is that the FCC would retain the ability to manipulate the marketplace, as they might perceive it, in the classification of a carrier as dominant versus competitive, and in the imposition of separate subsidiary requirements. The FCC does seem to have struck a balance on this issue. However, we are concerned about the rationale that identified GT&E as a dominant carrier. This could cause future concerns to some of the other Independent companies as they proceed to become larger entities in certain parts of the communications marketplace.

I don't believe there is any real difference of opinion today within the industry with respect to the need for legislation. What I'd like to do is develop the problem of working at the state level in the remaining time I have. In our view, the investment of new dollars in the terminal equipment market is mighty risky these days. The FCC or the state is still controlling our rate of capital recovery. The state commissions are still regulating our prices. But the competitive marketplace out there is determining the value and the obsolescence of our product. What assurances are we getting that we will really come out "whole" when we make an investment in the terminal equipment rate base? Market risk is one thing. That's something that we as businesses should take. But we should have the latitude to make our own mistakes. It seems to me that as telephone companies, we should begin work immediately with our state commissions on this problem.

It is our thought that our obligation as a supplier of last resort in the terminal market should immediately become limited. There are differences in commission attitudes on this question right now. In our own case, we have certain commissions who already would agree that such obligation should be severely limited; that except for maybe a basic black telephone, we should have no obligation. On the other hand, we have some state commissions who give us problems even in detariffing an item where manufacture has been discontinued.

I think pricing and tariff flexibility in the terminal market should be expanded. We should have greater ability to raise and lower prices as the market would dictate --- maybe higher prices on new products and the ability to lower prices on items that are obsolete. We should be required only to provide minimum notice in this kind of a market atmosphere for rate changes in the terminal market. We should be able to respond to seasonal and technological factors. As an example of flexibility, Centel, two years ago, proposed a plan which didn't seem to get much interest in the industry. The plan was to get a minimum lease guarantee period on telephone instruments under tariff. We were only asking for a 6-month minimum guarantee period. We do have contracts on PBXs, of course, but on the basic telephone set, we've had no protection. Surprisingly, very little interest was stimulated. But we wonder if this isn't the time now. If you're going to put an instrument in the rate base, there should be some guarantee period to protect you for the recovery of that investment.

Another example we pushed for is what we call our mandatory instrument return tariff which we had approved in Florida and Virginia. This allows Centel to charge customers who fail to return their set on outward movement, an amount equivalent to the net book value. If they don't return it, they own it. On the other hand, if they do return it to us, they get a $5 credit. Certainly this is a way to get our capital recovered. It's also a major step in lowering our "left-in-station" losses. I don't know if there is any company in the U.S. that's not experiencing this kind of problem in today's mixed environment of customer-owned equipment as well as telephone company-owned equipment.

Also, it seems to me that our depreciation rates should give maximum consideration to market factors. In the past, we've been asked to validate our depreciation rates on the basis of historical empirical studies. But the past is not important, it's the future in the marketplace which is important and this simply must be recognized in future terminal equipment depreciation rates. We also should be permitted to recover our capital through the direct sale of in-place plant and the direct sale of terminal equipment.

Another thing it seems to me is that in this environment, we should review with both federal and state commissions the collective impact of the Account 232 station equipment expensing as well as the future amortization we're going to experience as a result of the detariffing of terminal equipment. Are you really sure that we as telephone companies can develop our revenue requirements to cover both the amortization of our terminal equipment as well as our 232 investments? Certainly these should be coordinated because over 25% of our rate base investment is involved in terminal equipment.

Speaking of rates and regulation, I'd like to make another point. I don't know how many of you have looked at the inflation accounting results in the annual reports of the telephone companies of this country. It doesn't give you much assurance as to the adequacy of the capital recovery. We are able to keep our books to satisfy the accountants on the basis of what commissions regulate. But given inflation and given marketplace factors, we've really had inadequate recovery. So we find it a little bit incongruent in certain states to have to defend our rates and talk about refund. There's some necessity here for a different accounting process. Maybe we should be creating some reserves for future amortization.

A final point I would like to make is that the proper regulatory treatment of the local distribution network is critical to the future of the telephone companies. Certainly that local network is going to have competition from such things as cable television and cellular radio. However, it's my view that with technical enhancements, our local network has tremendous potential and increased value that has not been tapped at all. Many local type services which are being heralded as great achievements of cable television can be readily provided by the telephone companies' local network. Weather service, security systems, market reports, shopping by cable or wire, data retrieval networks and, with slow scan video, visual data retrieval are all already possible. And with technical enhancements the local network will have even more power as a competitive factor in tomorrow's telecommunications market.

However, there's one thing we need and we need badly, and that is local measured service. We need a pricing structure that will permit us to market these services and at the same time enhance our earnings. My thought is that it is far better for us to get this kind of enhancement in our earnings through greater usage than to have to raise the basic service threshold rate time after time to cover our revenue requirements. There's a lot of work for us before we get LMS. Obviously we must work with our regulators. We have a major problem with consumer groups. Both national and state consumer organizations have demonstrated an antagonistic view and we have to continue to work with these groups. Above all, we have a big customer education job to do. I don't think that the cost of measurement is any longer a problem, at least as you look to the future with digital central offices. It seems to me that every company should be working on a long range plan for local measured service. They should share it with their regulators and get concurrence on this method of meeting our revenue requirements in this very uncertain future.

So where do we end up on all this? Along with Mr. Geller, I couldn't agree more that we need new legislation. But we have to have reasonable ground rules to enable the industry to plan for the future and to participate in this exciting new marketplace. I think it's important that we not wait for the legislative and regulatory process to eventually give us all the answers. We should now move aggressively in every company to mitigate the consequences of this future change. We should be making our investment decisions in light of the inevitable. We should work to get fair and reasonable treatment from our regulators. We need flexibility. A healthy basic telecommunications system is in the public interest. We believe that a basic telecommunications network, in which all the telephone companies are partners, is essential to accomplishing this objective.

So we believe that we can move ahead, particularly if we have legislation that provides reasonable ground rules for the future.

Thank you.

SEVENTH SESSION, Wednesday, May 21, 1:15 p.m.

Concurrent Session C-3

ACCOUNTING FOR NUCLEAR FUEL CYCLE

CHAIRMAN: John B. Gillett, Partner
Requardt and Associates
Board of Directors, Iowa State Regulatory Conference

SPEAKERS: Richard W. Holmes
Assistant Controller
Duke Power Company

J. C. Robinson, Manager of Depreciation
and Nuclear Fuel Accounting
Northern States Power Company

ACCOUNTING FOR THE NUCLEAR FUEL CYCLE
NUCLEAR FUEL DISPOSAL COSTS
AT
DUKE POWER COMPANY

Richard W. Holmes
Assistant Controller
Duke Power Company

The application of good accounting principles and sound rate making policies for the electric utility industry charges all costs associated with generating electricity to the present user of that electricity. One of these costs, known as "disposal costs of nuclear fuel," is commonly misunderstood and has received wide publicity in the rate making sector. The purpose of this paper is to explain what is meant by disposal costs, give a brief background to its origin, and discuss the accounting and rate making treatment for disposal costs as applied at Duke Power Company.

Disposal Costs Defined

Disposal costs, as used here, arise from the "once-through" fuel cycle. The term "once through" refers to a fuel cycle in a nuclear reactor in which spent fuel assemblies are discharged from a reactor, then stored at a reactor site or at an independent storage facility for a period of time, and finally shipped to a federal repository. The spent fuel assemblies will be individually encapsulated and disposed of in a stable geologic formation. For the perpetual storage of this spent fuel, the Federal Government will levy a one-time fee to the utility. The amount of this fee is considered "disposal costs."

According to a Department of Energy report issued in July 1978 on "Preliminary Estimates of the Charge for Spent Fuel Storage and Disposal Services" (DOE/ET-0055), the one-time fee will be based on kilograms of heavy metal (uranium and plutonium) to be disposed. The amount of this fee includes the following cost components:

1. Geological repository in operation by 1988
2. An encapsulation facility located at the geological repository
3. Cost of decommissioning and surveillance of encapsulation facility and repository
4. All government research and development funds in support of commercial spent fuel disposal
5. Government overhead charge.

Duke Power Company estimates that this permanent storage and shipment of the spent fuel to the Federal repository would take place approximately ten years following discharge from the reactor.

Background

As of April 1977, the intended policy of the U. S. Government was to defer reprocessing of spent nuclear fuel indefinitely and to store this spent fuel discharged from commercial reactors in Federal storage facilities. This would seem to be the policy now only after the utility has exhausted all reasonable means of storing spent fuel on system. This action spurred electric utilities to reevaluate the cost of nuclear fuel being charged to their customers.

Prior to this time, utilities assigned a value to the spent fuel on the basis of reprocessing. Reprocessing captures the recoverable products contained in the spent fuel. It was estimated that the value of these recoverable products more than offset the cost of reprocessing. Hence, in determining the cost of the nuclear fuel charged to the customer, the customer received the credit for the net value of the spent fuel, commonly referred to as "net salvage value."

Under the U. S. Government Waste Management Program, the responsibility for developing facilities to dispose of high level wastes and spent fuel rests with the Department of Energy (DOE). Currently DOE's National Waste Terminal Storage Program is a three-pronged effort - The Office of Nuclear Waste Isolation managed by Battelle Columbus, the Basalt Waste Isolation Program managed by Rockwell Hanford Operations, and the Nevada Test Site investigations managed by the Nevada Operations Office of DOE. In a February 12, 1980 message to Congress, President Carter outlined his proposed program strategy, an outgrowth of the deliberations of his Interagency Review Group established in March of 1978. This strategy involves the evaluation of four or five potential repository sites in a variety of geologic environments with different host rock types. With respect to schedule, the President's message states "we should be ready to select the site for the first full-scale repository by 1985 and have it operational by the mid-1990's."

Accounting and Rate Making Treatment

Beginning in July 1977, Duke Power Company began recording as fuel expense, the estimated disposal costs to be incurred for the nuclear fuel burned each month. These costs were subsequently collected from the customer through the fuel adjustment clause mechanism. This accounting and rate making treatment was premised on the fact that the estimated costs of perpetual storage of unreprocessed spent fuel are properly treated as costs of nuclear fuel currently in use, and are therefore chargeable to the present customers over the period of the useful life of the fuel. The customers, however, would receive full benefit for the cash effect of the revenues derived from disposal costs until the Company makes a payment to the Federal Government.

To account for disposal costs over the period of the useful life of the fuel, it became necessary to estimate the disposal costs and state these costs per BTU of fuel used in the reactor. In establishing the disposal cost, the Company based its estimates on a report issued by the Nuclear Regulatory Commission (NRC) in August 1976, commonly referred to as the GESMO report on the Generic Environmental Statement on Mixed Oxide Fuel. This report recommended using $100 per kilogram of heavy metal for permanent disposal of the spent fuel with an additional $15 per Kg for shipping from the utility reactor site to the Federal repository. The costs were quoted in 1975 dollars.

Subsequent to this study, the North Carolina Utilities Commission (NCUC) issued in February 1977 their Report of Analysis and Plan: Future Requirements for Electricity Service to North Carolina. This report recommended $152/Kg for disposal and $53/Kg for shipping, both costs in 1975 dollars with an escalation rate of 5.5% compounded annually.

Naturally, all these costs include estimates of, among others, the future cost of a Federal repository and an encapsulation facility. Duke Power Company believes the estimates in the GESMO report are conservative. Indeed, in the previously mentioned DOE report (DOE/ET-055), the cost in 1978 dollars for disposal was estimated at $117 per kilogram. The comparable cost currently used by Duke Power is $117.42.

In Docket No. E-7, Sub 237, the NCUC set base rates at a level which would compensate the Company for estimated disposal costs on the nuclear fuel spent on an annual basis.

In addition, the Commission included in base rates a charge for the disposal costs on nuclear fuel spent prior to July 1977, the date the Company began charging the customer for disposal costs on fuel spent in that month. The disposal costs on the fuel spent prior to July 1977, including subsequent revisions, of approximately $66 million, however, is being collected from the customers over a ten-year period. By including the disposal costs as an identifiable element of cost in the base rates, this eliminated the need to collect these costs through the fuel cost adjustment mechanism.

In a recent North Carolina rate case, the North Carolina Utilities Commission approved an increase in the collection rate for disposal costs from 10.22¢/MBTU to 12.39¢/MBTU (from .0422¢ per KWH to .0548¢ per KWH). This new rate reflects the delay in the availability of the Federal repository from 1985 to 1988.

In summary, while we were originally computing a salvage credit in the 1973 to July 1977 period, we are now including disposal costs as an element of cost of service. The Carter Administration's decision to indefinitely defer commercial nuclear fuel reprocessing is greatly impacting the cost of supplying electricity from nuclear generation. Even with the additional disposal costs, however, the cost of nuclear generation still results in a tremendous savings to the electric customers.

"IDEAL" NUCLEAR FUEL CYCLE

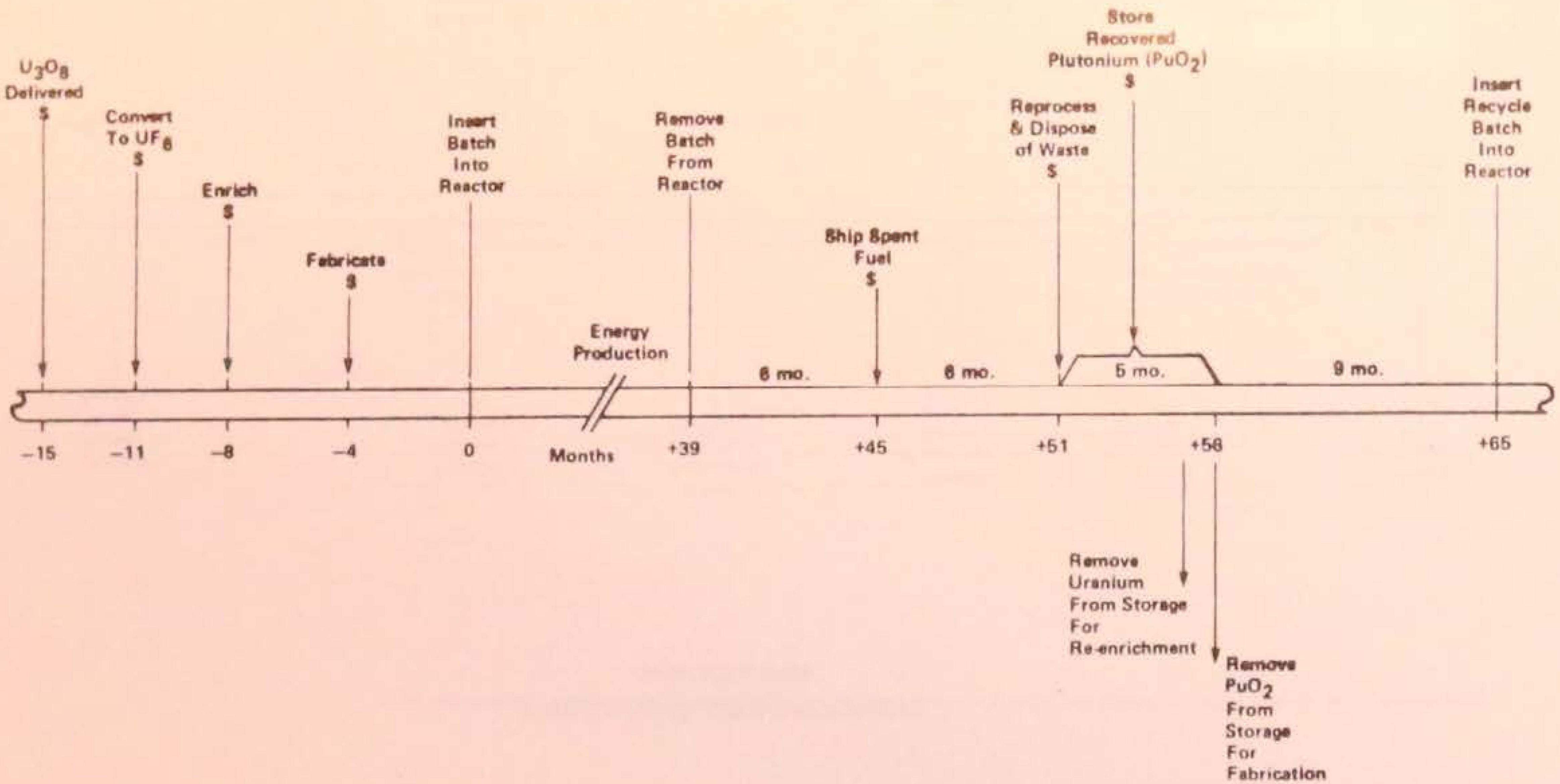


Table 1

NUCLEAR FUEL CYCLE (BACK END)
1976 SCENARIO

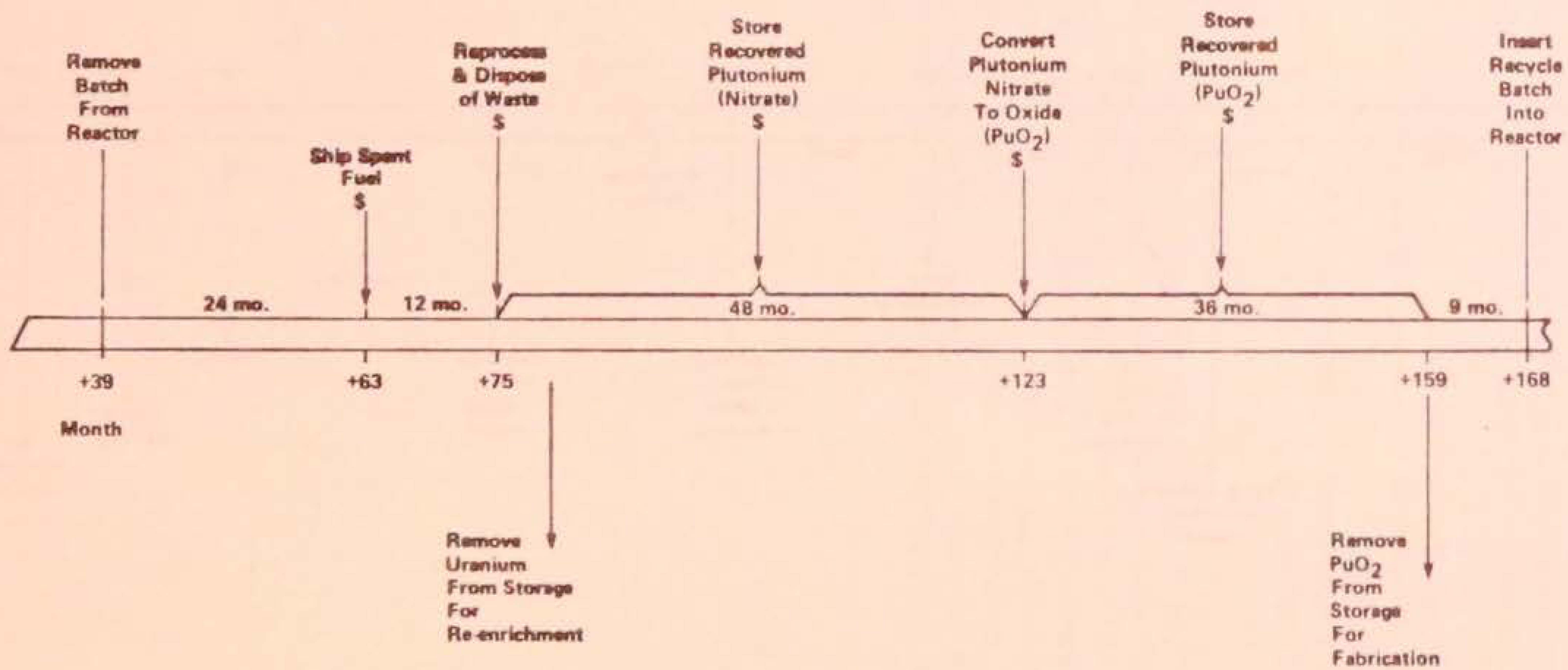
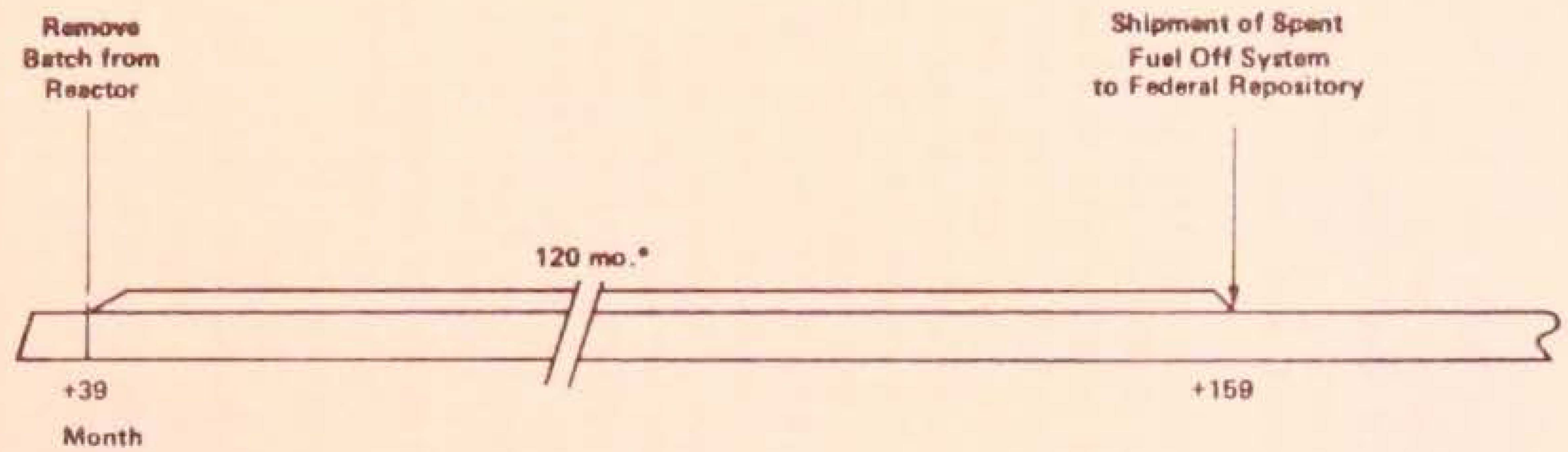


Table 2

Table 3

NUCLEAR FUEL CYCLE (BACK END)

1979 SCENARIO



* 10 year cooling period assumed, but no shipments of spent fuel to a Federal Repository are anticipated to occur before 1988.

A SINKING FUND APPROACH TO

NUCLEAR FUEL DISPOSAL RECOVERY

Jeffrey C Robinson
Manager
Depreciation and Nuclear Fuel Accounting
Northern States Power Company

The area of spent nuclear fuel has generated many questions and is surrounded by many uncertainties. The main question related to spent nuclear fuel is what should be done with it. Should the fuel be reprocessed? Permanently disposed of? What are the costs? What are the benefits? And what are the risks?

There are two basic cycles that can be assumed for the generation of electricity using nuclear fuel. Nuclear fuel, during its construction stage, involves mining and milling, processing, enrichment, and fuel assembly fabrication. After the assemblies have been fabricated, they are inserted into the reactor and are utilized to generate electricity. The burn period in the reactor covers a period of three to five years for most reactors. At the end of this period, the fuel is then removed from the reactor and placed into a temporary spent fuel storage facility. This facility is generally located at the plant site. Originally, it was assumed that after a cooling down period the spent fuel in temporary storage could be transported to a reprocessing facility and portions of the fuel could then be utilized to fabricate new fuel assemblies which is a reprocessing fuel cycle. The alternative cycle is to permanently dispose of the spent nuclear fuel in a federal disposal repository (exhibit I).

Under the original reprocessing assumptions, the period from the time that the fuel is discharged until such time that the fuel is shipped to a reprocessing facility is relatively short. Under the disposal assumptions, the period that the fuel must remain in temporary storage covers many years and seems to be getting longer due to delays in the construction of a permanent disposal facility by the federal government. These are the conditions that surround nuclear fuel disposal today (exhibit II-A).

The possibility still exists that these conditions could change and the time in the temporary fuel storage facility could get shorter. Even reprocessing is still a future possibility, thus making the variability of the wait period in temporary storage span a number of years (exhibit II-B).

The current policy must be to assume that spent nuclear fuel will be permanently disposed. This policy has been established by the President of the United States. The Department of Energy (DOE), in an attempt to establish some guidelines related to disposal costs which are consistent with the President's policy, has published estimates of charges to be paid by the utilities for shipping and permanent waste disposal. To determine the future disposal cost of nuclear fuel, the DOE cost estimates, which are in current dollars per kilogram of uranium ($KGU), can be applied to the number of kilogramms being disposed. This results in an estimate of disposal costs in current dollars. The next step in the process would be to estimate the year in which this disposal will occur and escalate these costs to the year of disposal. For example, if there were 28,600 KGU and an estimated current cost was $175/KGU, the disposal cost estimate would be $5.0 million in current dollars. If it was estimated that this fuel would not be disposed of for 15 years and the rate of escalation was 6%, the final anticipated disposal cost amount would be $12 million (exhibit III).

The procedure now being utilized to recover estimates of future disposal costs involves their recovery over the fuel's burn period. This recovery is linked to the burn of the fuel. This procedure is established by the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts, in paragraph A of Account 518 - Nuclear Fuel Expense.

> 518 NUCLEAR FUEL EXPENSE.
>
> A. This account shall be debited and account 120.5, Accumulated Provision for Amortization of Nuclear Fuel Assemblies, credited for the amortization of the net cost of nuclear fuel assemblies used in the production of energy. The net cost of nuclear fuel assemblies subject to amortization shall be the cost of nuclear fuel assemblies plus or less the expected net salvage of uranium, plutonium, and other byproducts and unburned fuel. The utility shall adopt the necessary procedures to assure that charges to this account are distributed according to the thermal energy produced in such periods.

If, for example, the $12 million estimated disposal cost were to be recovered for a fuel loading which had a three-year burn period and a uniform burn pattern, the recovery would be $4 million each year over the three-year period.

In looking at the recovery of disposal costs, it is important to look at all of the components of the cost and the revenue requirements needed to cover these costs. The three basic components of revenue requirements are return on net investment, capital recovery and income taxes. After calculating these components for this basic example, the timing of revenue requirements leads to a number of questions. Exhibit IV illustrates that the revenue requirements during the burn period are relatively high. After the fuel is discharged from the reactor, revenue requirements are negative and continue so until the fuel is disposed of permanently. During this period the rate base is reduced by the previous capital recovery and deferred income taxes. Because of the fact that no investment has been made by the utility, the rate base associated with disposal cost recovery is negative. This negative rate base then generates negative revenue requirements for the components of return and income taxes which are substantial. These negative requirements (benefits) remain constant over the entire period that the fuel is in temporary storage.

Is this the best way to recover these costs? It seems that the customers receiving the energy from the fuel should be responsible for generating the revenues needed for its disposal. Customers during the wait period between discharge and permanent disposal should not incur charges or receive any benefits because they have received no energy. Under the straight line recovery method, customers during this wait period do receive benefits resulting from the negative rate base. It seems that the appropriate way to recover these costs would be to lower the revenue requirements during the burn period of the fuel and have zero revenue requirements during the wait period. The recovery pattern associated with the future disposal cost can be altered so that these conditions will result.

This problem has been analyzed in detail at Northern States Power and associated computer programs have been developed to assist in this process. As a result of these studies, it was determined that a sinking fund recovery technique can be used to modify the recovery timing to result in an appropraite pattern of revenue requirements. Sinking fund recovery is what might be described as a slower than straight line method. The recovery pattern starts out low in the early years and increases each year. This is the reverse of the accelerated methods, such as SYD, being utilized in the computation of income tax depreciation (exhibit V-A). A unique feature of the sinking fund recovery technique is that this recovery pattern generates level annual revenue requirements, compared to the decreasing annual revenue requirements generated by straight line (exhibit V-B).

The sinking fund technique develops a recovery amount which is based on two components. The first component is an annuity amount and the second component is an interest amount computed on the recovery balance to date. Annually, these two components are combined to result in the recovery amount for the year. In the case of nuclear fuel disposal, this technique has been modified to allow the fixed recovery amount to span the in-service period of the fuel assemblies and the interest component covers the entire period from fuel insertion to ultimate disposal (exhibit VI).

When this technique is utilized, revenue requirements during the burn period of the fuel are reduced compared to the basic straight line recovery method. During the wait period for disposal, revenue requirements are zero rather than negative. When a comparison is made of the present worth of the revenue requirement pattern between the sinking fund technique and the basic straight line recovery technique, the sinking fund technique has fewer revenue requirements (exhibit VII).

In the development of this revenue requirement calculation, there are two basic assumptions which warrant detailed discussions. The first of these assumptions relates to the interest rate used to compute the sinking fund recovery. After comparing different interest rates, it was determined that a tax adjusted rate of return (r-tib) was the only rate that could be used to result in the desired revenue requirement pattern. When this particular rate is used, the revenue requirements that result during the burn period of the fuel become level provided the rate of burn is constant. This interest rate is also the only rate that can be used that will eliminate revenue requirements during the wait period for disposal. This is not to say that the tax adjusted rate of return should be used for other reasons such as discounting revenue requirements, but it is the appropriate rate to use when computing a sinking fund recovery for nuclear fuel disposal costs.

The second major assumption used in this revenue requirement computation is related to deferred income taxes. When dealing with a future cost such as the disposal cost associated with nuclear fuel, the recovery for tax purposes does not occur until the year of disposal. During the burn period of the fuel, income taxes are generated from the capital recovery of disposal costs. This is then offset in the final year by a large tax deduction when that cost is actually incurred. If a company normalizes major timing differences between taxes paid and tax benefits, it is important that these disposal cost timing differences be normalized. If normalization was not used, customers during the burn period of this fuel would also be paying for a large income tax component of revenue requirements only to have future customers receive a large tax break at the time of disposal. This obviously does not result in having the customers who receive all the energy provide for all of the costs and receive all of the benefits associated with that fuel. On the other hand, if a company uses flow-through accounting for other timing differences between book and tax recovery, the timing effect of nuclear fuel disposal costs should also flow through and the calculations included in this paper would have to be modified accordingly.

One of the biggest benefits of the proposed sinking fund recovery program is its ability to handle all of the variables surrounding nuclear fuel disposal cost recovery. The mechanics by which this approach is implemented becomes a very important factor in dealing with the variable components for nuclear fuel disposal recovery. Items such as rate of fuel burn, ultimate disposal costs, ultimate disposal dates, and interest rates are variables that will change from time to time while the fuel is in the core and in temporary storage. It is necessary that these changes be contemplated and dealt with in the design of a recovery system for nuclear fuel disposal. The following procedures provide the flexibility needed and also can be mechanized into a cost recovery system. The variables used in these equations can be defined as follows:

- B = assumed burn pattern
- D = disposal cost estimate (future dollars)
- U = future worth of unrecovered disposal costs
- R = reserve for disposal recovery
- T = sum of the annuity components for disposal cost recovery
- A = annual annuity component for disposal cost recovery
- t_0 = beginning of period = time zero
- t_1 = burn period = time elapsed from t_0 to end of burn
- t_2 = fuel cycle = time elapsed from t_0 to disposal of fuel
- n = number of years disposal cost has been recovered
- i = tax adjusted rate of return

Step 1 in this process is to determine the value of the future disposal cost estimate at a point in time which is the end of the burn period. This is accomplished by applying a present worth factor to the future disposal estimate.

$$D_{(t_1)} = D_{(t_2)} \times (1 + i)^{-(t_2 - t_1)}$$

Step 2 in this process is to determine the value of the unrecovered amount at the end of the burn period. This is accomplished by applying a future worth factor to the current recovery reserve and then subtracting that amount from the disposal value determined in

Step 1.

$$U_{(t_1)} = D_{(t_1)} - [R_{(n)} \times (1 + i)^{(t_1 - n)}]$$

The third step in this process is to make an assumption related to the future burn pattern of the fuel. The current burn percentage will be known at the time of the calculation, but it is necessary to make assumptions about the future burn pattern so that a future worth calculation can be linked to the rates of fuel burn and the time periods for accruing interest. The future burn assumptions could either be an engineering estimate or it could be assumed that the future burn is constant. The second assumption seems reasonable because of the fact that nuclear generating facilities are generally used as base load plants.

Step 4 in this process is to determine the total of the burn components for the sinking fund calculation. This is accomplished by deriving an amount so that when future worth factors are applied to the annual burn rates and accumulated throughout the fuel burn period, the result will equal the unrecovered amount determined in Step 2.

$$T = \frac{U_{(t_1)}}{\sum_{k=n}^{t_1} [B_{(k)} \times (1 + i)^{(t_1 - k)}]}$$

The final step in this process is to determine the annual burn component of the recovery. This is then accomplished by taking the current burn rate times the total recovery determined in Step 4.

$$A_{(n)} = T \times B_{(n)}$$

Exhibit VIII illustrates how the mechanics of this system are applied annually. In this example, the annual nuclear fuel burn rate varies over a three-year burn period and equal 40%, 25% and 35%, respectively. The original disposal estimate is $12 million and it is assumed that disposal will take place at the end of the 16th year.

Based on these assumptions, an interest accruing recovery pattern is developed over the burn period and linked to the annual burn rates such that when the accumulation of the recovery and interest components is made, it will total the future disposal estimate by the end of the 16th year. To further illustrate the flexibility of this approach, in the 9th year it is assumed that the tax adjusted interest rate will change from 8.18% to 9.66%. Also at this time, the disposal estimate is increased from $12 million to $15 million and the wait period for disposal is extended one year. Based on the future value of the recovery to date when compared to the new disposal cost estimate, an annual annuity can be developed over the years remaining so that the recovery by the end of the 17th year equals the new disposal estimate. Note that the annuity portion is less than $25 thousand and results in the recovery of the additional $3 million in disposal costs. This illustrates the fact that assumptions can vary without a large fluctuation in capital recovery under this system.

It is appropriate and timely to review and modify the recovery assumptions related to nuclear fuel disposal costs. The sinking fund technique which I am proposing provides for the recovery of ultimate disposal costs and has a lower present value of revenue requirements when compared with straight line recovery. In theory, customers who receive the energy from the nuclear fuel incur all of these costs. Customers during the wait period for disposal incur no costs and receive no unwarranted benefits. Finally, this recovery proposal has the flexibility to recover costs even though assumptions and estimates will change, and does so without large fluctuations in capital recovery.

EXHIBIT I

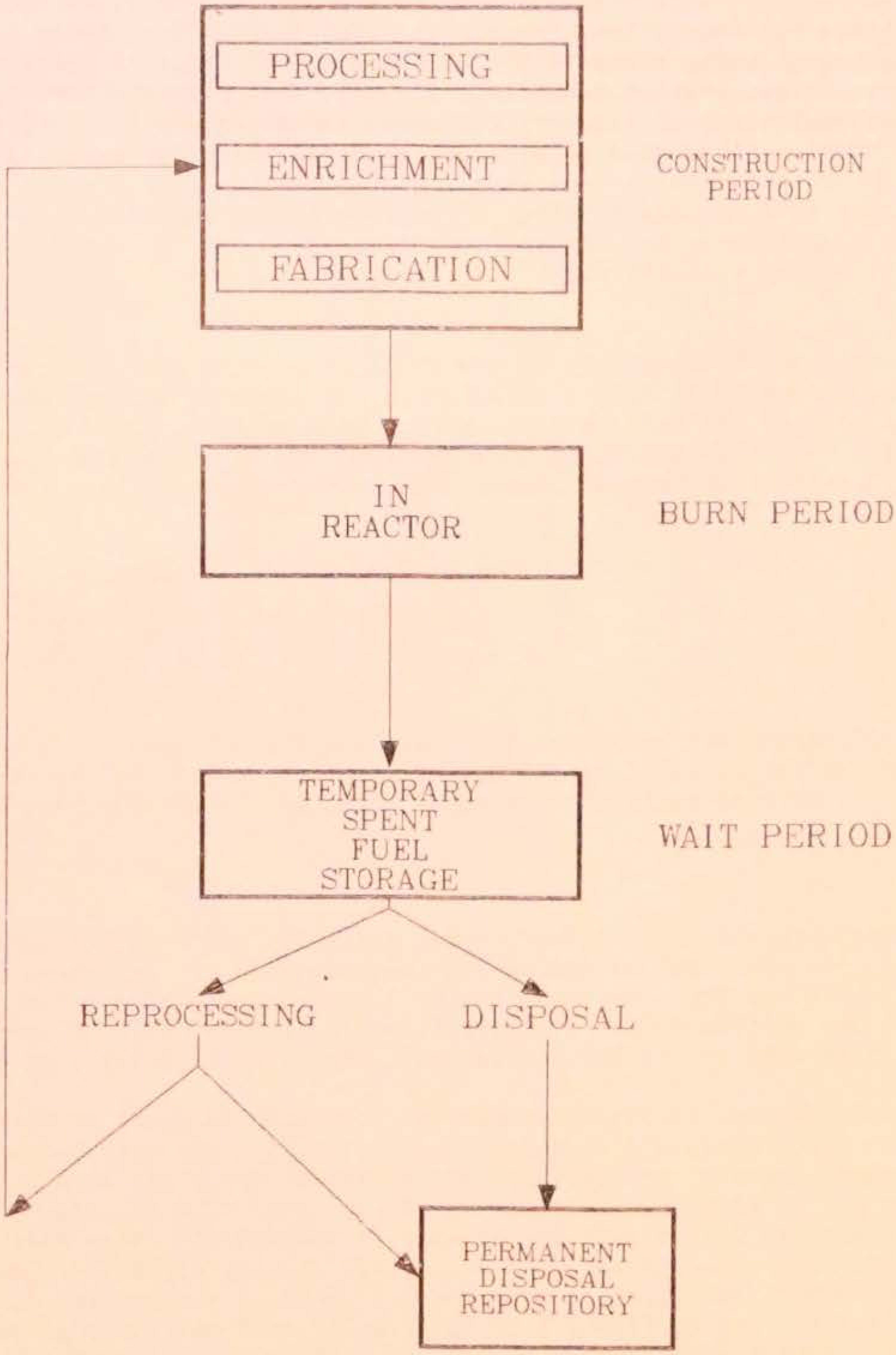

PROCESSING
ENRICHMENT
FABRICATION
CONSTRUCTION PERIOD
IN REACTOR
BURN PERIOD
TEMPORARY SPENT FUEL STORAGE
WAIT PERIOD
REPROCESSING
DISPOSAL
PERMANENT DISPOSAL REPOSITORY

Exhibit II

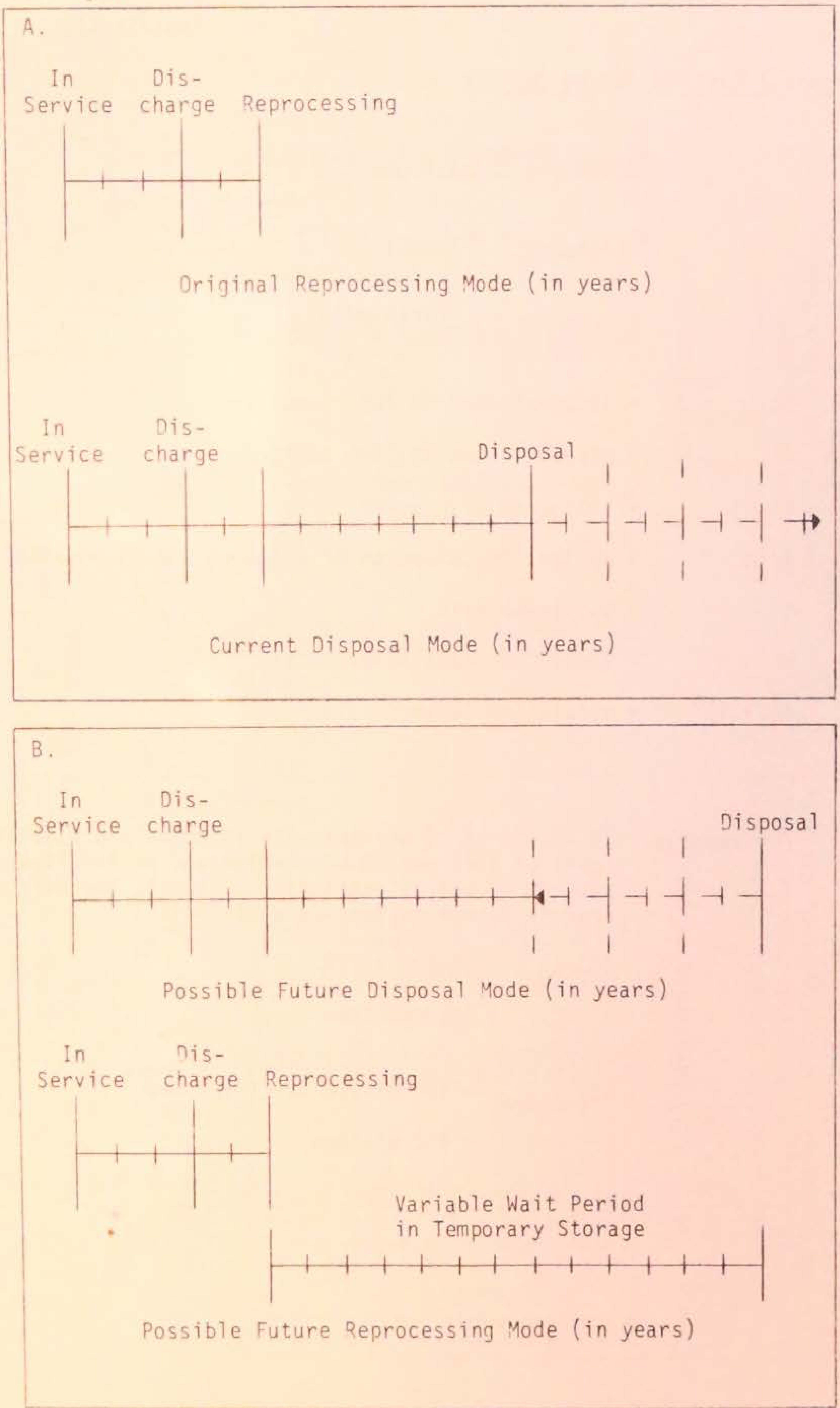

A.
In Service
Dis-charge
Reprocessing
Original Reprocessing Mode (in years)
In Service
Dis-charge
Disposal
Current Disposal Mode (in years)
B.
In Service
Dis-charge
Disposal
Possible Future Disposal Mode (in years)
In Service
Dis-charge
Reprocessing
Variable Wait Period in Temporary Storage
Possible Future Reprocessing Mode (in years)

Exhibit III

Disposal Cost in Future Dollars

$$DC_{(1980)} = KG_{(uranium)} \times \$/KG$$

$$DC_{(future)} = DC_{(1980)} \times (1 + i)^n$$

$$= (KG_{(uranium)} \times \$/KG) \times (1 + i)^n$$

$DC_{(future)}$	= disposal cost in future dollars
$DC_{(1980)}$	= disposal cost in 1980 dollars
$KG_{(uranium)}$	= kilograms of uranium
$/KG	= dollars per kilogram of shipping and disposal cost
i	= inflation rate
n	= number of years to disposal
$(1 + i)^n$	= escalation factor

For example: If 12,600 KG of uranium with shipping and disposal costs of $175 per KG of uranium and an inflation rate of 6% and 15 years till disposal, the disposal cost in future dollars is as follows:

$$DC_{(1980)} = 28{,}600 \times 175$$

$$= \$5.0 \text{ million}$$

$$DC_{(future)} = 5.0 \text{ million} \times (1 + 0.06)^{15}$$

$$= \$12 \text{ million}$$

Exhibit IV

NUCLEAR FUEL DISPOSAL COST RECOVERY
REVENUE REQUIREMENTS (ST. LINE RECOVERY)
(values in thousands)

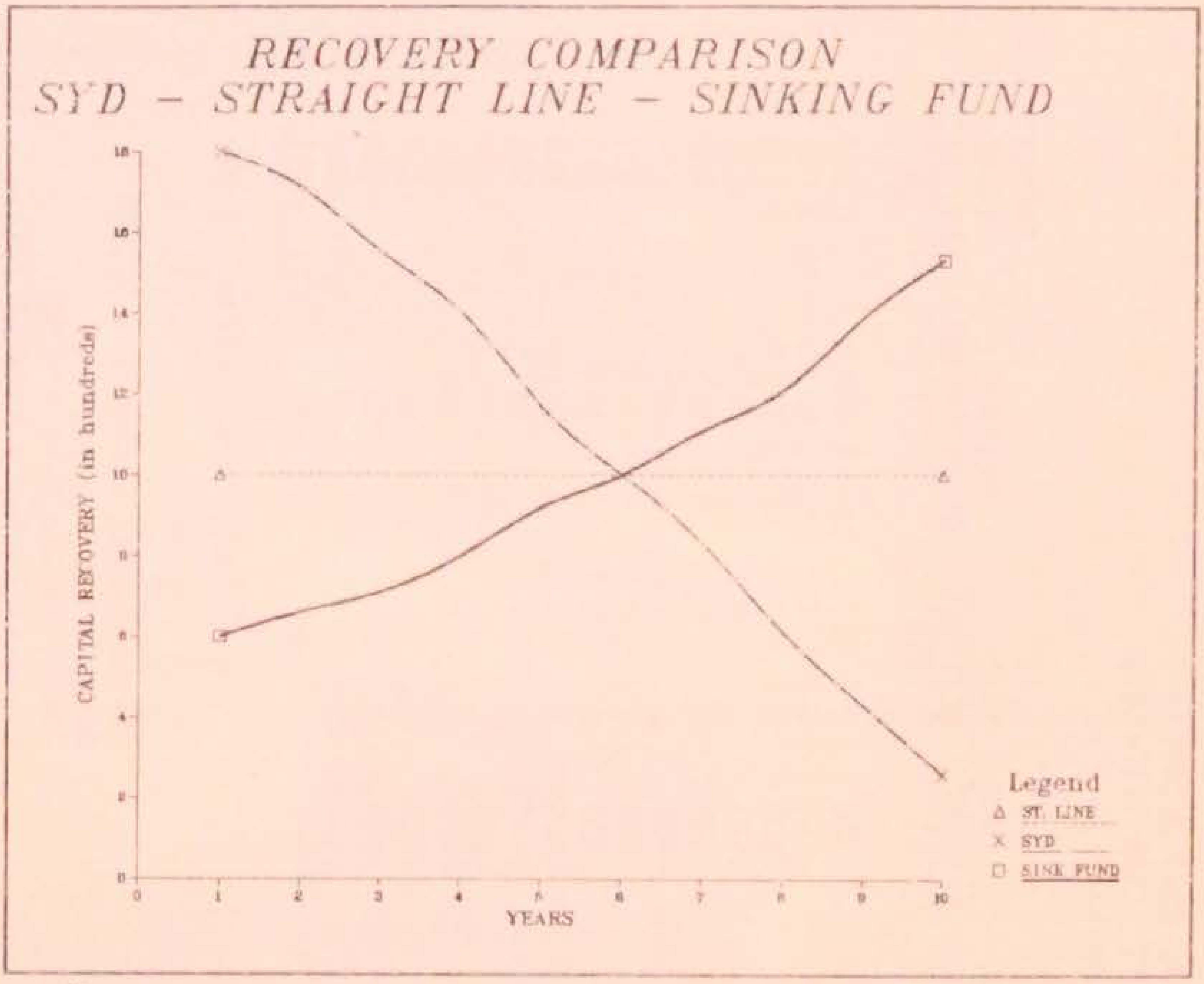
YEAR	BEGINNING RATE BASE (1)	RETURN DEBT 50% @ 7% (2)	RETURN EQUITY 50% @ 13% (3)	DISPOSAL EXPENSE (4)	INCOME TAXES CURRENT (5)	INCOME TAXES DEFERRED (6)	REVENUE REQUIREMENTS (7)	PRESENT VALUE REV. REQ. (8)
1980	0	0	0	4 000	2 080	-2 080	4 000	3 636
1981	-1 920	-67	-125	4 000	1 945	-2 080	3 673	3 036
1982	-3 840	-134	-250	4 000	1 809	-2 080	3 345	2 513
1983	-5 760	-202	-374		-405	0	-981	-670
1984	-5 760	-202	-374		-405	0	-981	-609
1985	-5 760	-202	-374		-405	0	-981	-554
1986	-5 760	-202	-374		-405	0	-981	-503
1987	-5 760	-202	-374		-405	0	-981	-458
1988	-5 760	-202	-374		-405	0	-981	-416
1989	-5 760	-202	-374		-405	0	-981	-378
1990	-5 760	-202	-374		-405	0	-981	-344
1991	-5 760	-202	-374		-405	0	-981	-313
1992	-5 760	-202	-374		-405	0	-981	-284
1993	-5 760	-202	-374		-405	0	-981	-258
1994	-5 760	-202	-374		-405	0	-981	-235
1995	-5 760	-202	-374		-6 645	6 240	-981	-213
							Total Present Value	3 950

(1) = - (4) - (6) [Beginning of year]
(2) = (1) x .50 x .07
(3) = (1) x .50 x .13
(4) = Disposal Cost Cost Estimate ÷ Burn Period
(5) = t/1-t x [(3) + (4) + (6) - tax deduction]
(6) = Tax Deduction - (4) x Composite Tax Rate
(7) = (2) + (3) + (4) + (5) + (6)
(8) = (7) x (P/F) factor

Disposal Cost Estimate = 12,000
Burn Period = 3 years
Composite Tax Rate = 0.52
Discount Factor = Rate of Return = 10%
Tax Deduction = 12,000 (in last year only)

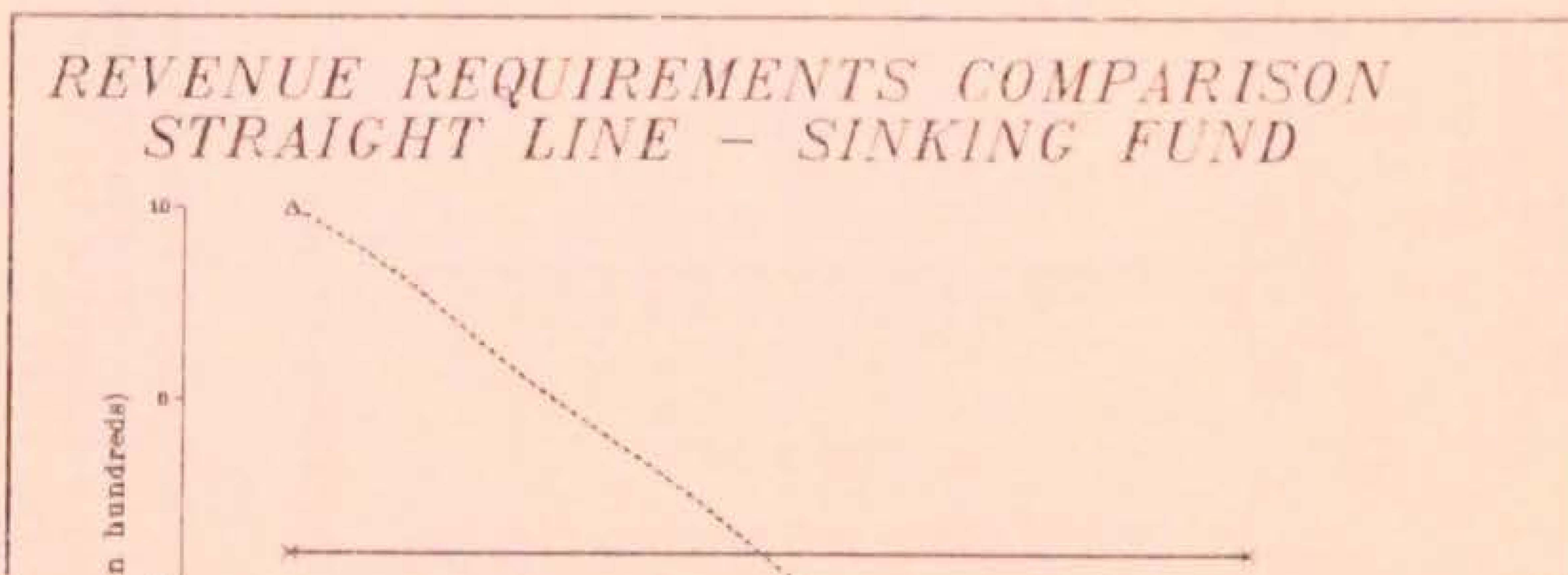
EXHIBIT V

A



RECOVERY COMPARISON
SYD - STRAIGHT LINE - SINKING FUND
CAPITAL RECOVERY (in hundreds)
YEARS
Legend
ST. LINE
SYD
SINK FUND

B



REVENUE REQUIREMENTS COMPARISON
STRAIGHT LINE - SINKING FUND
REVENUE REQUIREMENTS (in hundreds)
YEARS
Legend
ST. LINK
SINK FUND

Exhibit VI

SINKING FUND RECOVERY
(values in thousands)

YEAR	ANNUITY COMPONENT	INTEREST COMPONENT	TOTAL YEARLY RECOVERY
1980	1 328	0	1 328
1981	1 328	109	1 437
1982	1 328	226	1 554
1983		353	353
1984		382	382
1985		414	414
1986		447	447
1987		484	484
1988		523	523
1989		566	566
1990		612	612
1991		662	662
1992		717	717
1993		775	775
1994		839	839
1995		907	907
TOTAL	3 984	8 016	12 000

Exhibit VII

NUCLEAR FUEL DISPOSAL COST RECOVERY
REVENUE REQUIREMENTS (SINKING FUND RECOVERY)
(values in thousands)

YEAR	BEGINNING RATE BASE (1)	RETURN DEBT 50% @ 7% (2)	RETURN EQUITY 50% @ 13% (3)	DISPOSAL EXPENSE (S.F.) (4)	INCOME TAXES CURRENT (5)	INCOME TAXES DEFERRED (6)	TOTAL REVENUE REQUIREMENTS (7)	PRESENT VALUE REV. REQ. (8)
1980	0	0	0	1 328	690	-690	1 328	1 207
1981	-638	-22	-42	1 437	702	-747	1 328	1 098
1982	-1 328	-47	-86	1 554	715	-808	1 328	998
1983	-2 074	-73	-135	353	38	-183	0	0
1984	-2 244	-78	-146	382	41	-199	0	0
1985	-2 427	-85	-158	414	44	-215	0	0
1986	-2 626	-92	-171	447	48	-232	0	0
1987	-2 841	-99	-185	484	52	-252	0	0
1988	-3 073	-107	-200	523	56	-272	0	0
1989	-3 324	-116	-216	566	60	-294	0	0
1990	-3 596	-126	-234	612	66	-318	0	0
1991	-3 890	-136	-253	662	71	-344	0	0
1992	-4 208	-147	-273	717	76	-373	0	0
1993	-4 552	-159	-296	775	83	-403	0	0
1994	-4 924	-172	-320	839	89	-436	0	0
1995	-5 327	-186	-346	907	6 143	5 768	0	0
							Total Present Value	3 303

(1) = - (4) - (6) [Beginning of year]
(2) = (1) x .50 x .07
(3) = (1) x .50 x .13
(4) = (Disposal Cost Estimate x (F/P) factor) + [(Recovery Reserve)] x .0818
(5) = t/1-t x [(3) + (4) + (6) - tax deduction]
(6) = Tax deduction - (4) x Composite Tax Rate
(7) = (2) + (3) + (4) + (5) + (6)
(8) = (7) x (P/F) factor

Disposal Cost Estimate = 12,000
Burn Period = 3 years
Composite Tax Rate = 0.52
Discount Factor = Rate of Return =10%
Tax Deduction = 12,000
(in last year only)

Exhibit VIII

EXAMPLE

NUCLEAR FUEL DISPOSAL COST RECOVERY
EXAMPLE WITH VARIABLE PARAMETERS

ASSUMPTIONS

Disposal cost - variable

Burn period - variable

Burn pattern - variable

Interest rate (i) - variable

Disposal takes place at the end of burn

T = recovery total used for annual calculation

Wait period (n) - variable

Values In ,000's

YEAR 1

INFORMATION

Disposal cost estimate = 12,000

Burn period = 3 years

Interest Rate (i) = 10%, Tax adjusted interest rate = 8.18%

Annual burn pattern: 1st year = .40
2nd year = .25
3rd year = .35

Wait period = 13 years

Present worth of disposal cost estimate = $12{,}000 \times (1 + i)^{-n}$

$= 12{,}000 \times .3598233 = 4317.88$

ASSUMED BURN PATTERN		FUTURE WORTH		TOTAL RECOVERY	
.4	x	$(1 + i)^2$	x	T	
+.25	x	$(1 + i)^1$	x	T	
+.35	x	$(1 + i)^0$	x	T	= 4317.88

$T = 4317.88/(.4 \times 1.1703 + .25 \times 1.0818 + .35)$

$= 4317.88/1.08857$

$= 3966.56$

Recovery (1) = 3966.56 x .4 = 1586.62

Reserve = 1586.62

YEAR 2

INFORMATION

Disposal cost estimate = 12,000

Burn period = 3 years

Tax adjusted interest rate = 8.18%

Annual burn rate = 2nd year = .25
3rd year = .35

Wait period = 13 years

Present worth of disposal cost estimate = $12{,}000 \times (1 + i)^{-n}$

$= 12{,}000 \times .3598233 = 4317.88$

Future worth unrecovered = $4317.88 - 1586.62 \times (1 + i)^2$

$= 4317.88 - 1586.62 \times 1.1703$

$= 4317.88 - 1856.82 = 2461.06$

ASSUMED BURN PATTERN		FUTURE WORTH		TOTAL RECOVERY	
.25	x	$(1 + i)^1$	x	T	
+.35	x	$(1 + i)^0$	x	T	= 2461.06

T = 2461.06/(.25 x 1.0818 + .35)

T = 2461.06/(0.6205) = 3966.25

Recovery (2) = 3966.25 x .25 = 991.56

Reserve = 1586.62 + (1586.62 x 8.18%) + 991.56 = 2707.97

YEAR 3

Future worth unrecovered = $4317.88 - 2707.97 \times (1 + i)^1$

$= 4317.88 - 2707.97 \times 1.0818$

$= 4317.88 - 2929.48 = 1388.40$

ASSUMED BURN PATTERN		FUTURE WORTH		TOTAL RECOVERY		
.35	x	$(1 + i)^0$	x	T	=	1388.40

T = 1388.40/(.35)

= 3966.86

Recovery (3) = 3966.86 x .35 = 1388.40

Reserve = 2707.97 + (2707.97 x 8.18%) + 1388.40

= 4317.88

$\boxed{\text{YEAR 4 - 8}}$ Interest is calculated on the reserve at 8.18% only.

$\boxed{\text{YEAR 9 - 17}}$ INFORMATION

Disposal cost estimate = 15,000

Burn period = 3 years

Interest rate (i) = 12%
tax adjusted interest rate = 9.66%

Wait period = 14 years

Unrecovered burn = disposal cost estimate - (reserve (8) x (F/P) factor)

= 15,000 - (6397.42 x $(1 + i)^n$)

= 15,000 - 14670.30 = 329.70

Annuity for a future amount of 329.70 = 329.70 x $\frac{i}{(1 + i)^n - 1}$

= 24.63

RECOVERY SUMMARY

YEAR	BURN RATE	BEGINNING OF YEAR RESERVE	DISPOSAL CHARGE COMPONENT	INTEREST COMPONENT	ANNUAL RECOVERY	END OF YEAR RESERVE
1980	.40	0	1 586 620	0	1 586 620	1 586 620
1981	.25	1 586 620	991 560	129 790	1 121 350	2 707 970
1982	.35	2 707 970	1 388 400	221 510	1 609 910	4 317 880
1983		4 317 880	0	353 200	353 200	4 671 080
1984		4 671 080	0	382 090	382 090	5 053 170
1985		5 503 170	0	413 350	413 350	5 466 520
1986		5 466 520	0	447 160	447 160	5 913 680
1987		5 913 680	0	483 740	483 740	6 397 420
1988		6 397 420	24 630	617 990	642 620	7 040 040
1989		7 040 040	24 630	680 070	704 800	7 744 740
1990		7 744 740	24 630	748 140	772 770	8 517 510
1991		8 517 510	24 630	822 790	847 420	9 364 930
1992		9 364 930	24 630	904 650	929 280	10 294 210
1993		10 294 210	24 630	994 420	1 019 050	11 313 260
1994		11 313 260	24 630	1 092 860	1 117 490	12 430 750
1995		12 430 750	24 630	1 200 810	1 225 440	13 656 190
1996		13 656 190	24 630	1 319 180	1 343 810	15 000 000

EIGHTH SESSION, Wednesday, May 21, 3:00 p.m.

Concurrent Session D-2

CURRENT ISSUES IN ACCOUNTING AND RATE-MAKING

CHAIRMAN: John F. Utley

SPEAKER: Raymond F. Dacek, Esq.
Reid & Priest

DEVELOPMENTS RELATING TO THE ACCOUNTING TREATMENT OF THE INVESTMENT TAX CREDIT AND ACCELERATED DEPRECIATION FOR PUBLIC UTILITY RATEMAKING PURPOSES

RAYMOND F. DACEK
PARTNER
REID & PRIEST

I. Decision No. 87838 - California Public Utilities Commission (CPUC) - September 13, 1977.
   1. Rate decision involving Pacific Telephone and Telegraph Company (Pacific Telephone) and General Telephone Company of California (General Telephone).
   2. Treatment of investment tax credit and accelerated depreciation.
   3. National Office of Internal Revenue Service holds that methodology is inconsistent with section 46(f) (investment tax credit) and section 167(l) (accelerated depreciation) of the Internal Revenue Code.
   4. CPUC's "AAA" method for accelerated depreciation and "AA" for investment tax credit.
   5. California Supreme Court, on July 13, 1978, denied, without opinion, a petition for review of Decision No. 87838.
   6. U. S. Supreme Court, on December 12, 1978, denied petition for certiorari.
   7. Petition for declaratory and injunctive relief.
      A. U. S. District Court, Northern District of California, denied motion for preliminary injunction.
      B. This denial was affirmed by the United States Court of Appeals for the 9th Circuit on July 18, 1979.
      C. U. S. Supreme Court, on August 13, 1979, denied an application for a stay sought in connection with a petition for certiorari.
   8. CPUC, on February 13, 1980, issued its order implementing Decision No. 87838 for Pacific Telephone and General Telephone.
      A. Companies were directed to make refunds for the period prior to the date of the order, $363 million plus interest for Pacific Telephone and $86 million plus interest for General Telephone.
      B. Refunds not to exceed $35 per subscriber are to be paid within 120 days of order - the remaining refunds are to be paid one year thereafter.

C. Prospective rates for the two companies, however, are based on full normalization of investment tax credit and accelerated depreciation, subject to refund.

9. The Internal Revenue Service has issued a tax deficiency notice to Pacific Telephone in the amount of $89 million plus interest for the 1974 tax year based upon the company's loss of eligibility of investment tax credit and accelerated depreciation.

10. Pacific Telephone has paid the tax deficiency and is preparing to litigate the tax issues.

II. The Legislative Front - H.R. 6806 and H.R. 3165

1. H.R. 6806

A. Background - with certain exceptions, under present law electric, gas, telephone and other utilities are required to normalize the tax benefits resulting from investment tax credit and accelerated depreciation - violation of normalization provisions may result in loss of investment tax credits and accelerated depreciation (e.g., see above).

B. H.R. 6806, for certain orders of public utility commissions entered prior to January 1, 1980, would forgive past violations.

C. The proposed legislation, in effect, purports to "exonerate" Pacific Telephone, General Telephone and the CPUC for past failures to normalize.

2. H.R. 3165

A. Background - relative to investment tax credits with certain exceptions, under present law electric, gas, telephone and other utilities may be required to sustain either a pro rata flow through to cost of service <u>or</u> a pro rata adjustment to rate base - violation may result in loss of investment tax credits.

B. H.R. 3165 would permit a pro rata flow through to cost of service <u>and</u> a pro rata adjustment to rate base.

C. Hearings, Committee on Ways and Means, U. S. House of Representatives, April 15, 1980 (see, Appendix).

Raymond F. Dacek

APPENDIX

HIGHLIGHTS OF TRANSCRIPT (UNEDITED)

HEARINGS BEFORE THE
COMMITTEE ON WAYS AND MEANS
U.S. HOUSE OF REPRESENTATIVES

LEGISLATIVE PROPOSALS RELATING TO THE ACCOUNTING
TREATMENT OF THE INVESTMENT TAX CREDIT AND ACCELERATED
DEPRECIATION FOR PUBLIC UTILITY RATEMAKING PURPOSES

Washington, D. C.
April 15, 1980

Witness	H.R. 6806	H.R. 3165	Comments on H.R. 6806
Daniel I. Halperin, Deputy Assistant Secretary for Tax Legislation, Department of The Treasury	Uncommitted	For (A)	(1) "***legislation might be preferable that prescribes some measure of sanction ***." (Tr. pg. 10) (2) "We need *** to get more of a feel about it, the likely impact in California, as well as its impact in other states." (Tr. pgs. 10-11) (3) "As far as we know, there are no similar problems with other states." (Tr. pg. 24)
Theodore F. Brophy, Chairman of The Board, General Telephone and Electronics Corp.	For	Against	(1) "We suggest that H.R. 6806 is an equitable solution because it removes the uncertainty of protracted litigation. It protects the utilities from the inequitable payment of back-taxes *** and *** protects the utilities ability to provide service to their ratepayers." (Tr. pg. 42)

Witness	H.R. 6806	H.R. 3165	Comments on H.R. 6806
			(2) "Treasury has told you that they will support H.R. 6806 only if it leads to a termination of the litigation." (Tr. pg. 43)
Robert N. Flint, Vice President and Comptroller American Telephone and Telegraph Co.	For	Against	(1) "The existence of these potential tax deficiencies has cast a cloud on the ability of the Pacific Telephone and Telegraph Company to finance the requirements of construction." (Tr. pg. 48)
John E. Bryson, President, California Public Utilities Commission	Against (8)	For	(1) "Unfortunately, the bill before you, H.R. 6806, will not resolve the problem, and indeed, will only create new complications and uncertainties." (Tr. pg. 51) (2) "If H.R. 6806 is enacted, it will be seen as special legislation for the companies, and will open the door for additional years of dispute." (Tr. pg. 52) (3) "***under the terms of the California Supreme Court's orders to us we may still be compelled to seek a method other than that traditionally advocated by the companies." (Tr. pg. 56) (4) "***even if the Commission were to grant the companies the method of normalization they prefer, there

Witness	H.R. 6806	H.R. 3165	Comments on H.R. 6806
			is no doubt but that intervenors would again sue and take the matter to the Supreme Court." (Tr. pg. 57)
Burt Pines, City Attorney, City of Los Angeles	Against	For	(1) "However, if the kind of solution that Mr. Bryson suggested could be adopted, that is essentially to authorize the kind of normalization adopted by the California PUC for California, we would support it." (Tr. pg. 66)
Gordon R. Corey, Chairman, Cost of Money and Taxes Committee, Edison Electric Institute and Former Vice Chairman, Commonwealth Edison Co.	-(C)	Against	(1) "***we recognize the refusal of the Public Utility Commission of California to abide by the will of the Congress as expressed in sections 46 and 167 presents this committee with a difficult problem." (Tr. pg. 108)
Jerome J. McGrath, President, Interstate Natural Gas Association of America	Do Not Support	Against	(1) "Our inability to support H.R. 6806, however, arises from our concern that it may be construed by some as a Congressional license to depart from what is the clear Federal policy with respect to the treatment of accelerated depreciation and the investment tax credit for ratemaking purposes. We are also concerned that H.R. 6806 * will not be successful in providing any more certainty than the

Witness	H.R. 6806	H.R. 3165	Comments on H.R. 6806
			statutory language and regulations that are currently in effect." (Tr. pg. 111)
Horace W. Breece, Jr., Comptroller, National Association of Water Companies, American Water Works Services Company	No Position	Against	(1) "***[no position] except to say that it [H.R. 6806] will provide a way out of the widely publicized dilemma in which two California utilities presently find themselves, some solution to that predicament would certainly appear to be in everyone's best interest." (Tr. pg. 116)
Brian Lederer, People's Counsel, District of Columbia	-(D)	-(D)	See Footnote (D)
Robert S. McIntyre, Director, Tax Reform Research Group	No Comment	For	-------

FOOTNOTES

(A) "***the principle issue that H.R. 3165 really comes down to is how much capital is to be considered to have been supplied by the shareholders toward the purchase of that machinery." (Tr. pg. 12)

"***we believe it is simply improper to justify improper normalization of the investment credit as an antidote to deficiencies in the ratemaking process." (Tr. pg. 13)

(B) "The appropriate solution in our judgment is to freeze the status quo ***. This would permit continuing use of AAA and AA normalization by companies already employing that method ***." (Tr. pg. 58)

(C) "A few of us, Commonwealth Edison included, regard H.R. 6806 as the lesser of possible evils and so we have decided with reluctance and misgivings not to oppose the bill, but we hope and pray the California malady will not spread.

Most of our industry, however, is opposed to H.R. 6806 and believes that the provisions of Sections 46 and 167 should not be modified and should be enforced. All of us would unalterably oppose extension of the proposed grandfathering provisions to any form of flowthrough beyond 1979." (Tr. pg. 109)

(D) "*** it [Congress] ought to eliminate entirely those sections of the Code that condition public utility eligibility for the investment tax credit and for accelerated depreciation on the state ratemaking treatment." (Tr. pg. 127)

HEARINGS, APRIL 15, 1980 (CONTINUED)

Some of the more colorful or interesting statements:

1. Mr. Frenzel

"Maybe we should be repealing the California PUC rather than worrying about ways to keep them from mischief ***." (Tr. pg. 34)

"***it seems to me the Public Utlity [sic] Commission of California is using the United States taxpayer to subsidize the utility users of the state [sic] of California." (Tr. pg. 35)

"But, it does seem terribly unfair. If this state gets away with it, the others should, too." (Tr. pg. 36)

"There was never an intent to use the federal tax dollars to give some special rates to certain favored citizens in some states of the country. I think it is a dreadful mistake, what the PUC has done, and I am a little bit at a loss as to where to go from here. But it seems to me that Mr. Stark's bill preserves the inequity and it seems to me the suggestion of Mr. Bryson exascerbates the inequity and I do not want my federal taxpayers paying refunds for the telephone users of the state [sic] of California." (Tr. pg. 93)

2. Mr. Corman

"I am searching frantically, Mr. Stark, for something that will please the city attorney and the Congressman from Minnesota. I am not sure there is such a thing, but we are looking for it." (Tr. pg. 38)

3. Mr. Pines

"***the Utilities Commission [California] in 1968 imputed accelerated depreciation with flow-through because of their [the telephone companies] imprudent management. That is the characterization of the PUC and the California Supreme Court. *** When it comes to the innocence here, I do not think it is fair for the telephone companies to describe themselves as the innocents and the Public Utilities Commission as somehow the culprit." (Tr. pg. 64)

"We do not believe there is going to be a tax liability. Obviously your Treasury witness does. We believe the PUC method here, the normalization methodology they utilize is legal, is a proper thing *** and there would not be a liability. *** If somehow this bill could be amended to allow the California methodology both past and future, I think that would resolve and avoid any contingent tax exposure." (Tr. 78-79)

4. Mr. Conable

"If I may say so, I think the practices in California sell the future short. I think you are going to wind up with lousy utilities out there and lousy service, and your future consumers will have you people to thank. ***that you [to Mr. Pines] are not willing to accept any responsibility through the rate structure for providing for reasonable cost of capital formation, and I do not like it and I feel quite strongly about it." (Tr. pg. 79)

5. Mr. Brophy

"The intention [of the investment tax credit] was to create capital for the long haul." (Tr. pg. 84)

NOTE: Mr. Stark was stating that the credit was intended to reduce the cost of acquiring depreciable assets.

"We will not be able to keep up with that growth and also modernize unless we can get adequate returns to attract capital. Only recently we had to withdraw an issue of preferred stock for General Telephone Company, a preference stock, because we could find no purchasers for the stock in the climate that existed." (Tr. pgs. 91-92)

6. Mr. Flint

"***the purpose of this [investment tax credit] was to stimulate additional investment since it increases the expected profit from their use." (Tr. pg. 87)

7. Mr. Stark

"You are getting all of the benefits from us and it is what you are doing in the ratemaking, and we have already given you [an investment credit] out of the taxpayers' pocket. You are trying to take it out a second time from those poor taxpayers that you peddle your services to by clipping them a second time. I submit the double dipping is above and beyond the call of good corporate management." (Tr. pg. 85)

8. Mr. Corey

"If the Congress wishes investment tax credit to be effective, they should not take steps, at this time in particular, to mute their effect. I am afraid that this is just what H.R. 3165 would do one way or another." (Tr. pg. 107)

"***we would rather have seen the problem dealt with in a somewhat different way than proposed by H.R. 6806. For example, rather than saying, in fact, 'Thy sins are forgiven, go now and do not sin again,' rather than that, we would have preferred to have the Congress re-affirm that intent of Sections 46(f) and 167(l) as they now stand and to provide that some penalty be imposed against California, however small." (Tr. pg. 108)

9. Mr. McGrath

"The provisions of H.R. 6806 relating to 'inconsistent adjustments' tend to be abstract and, given the complexity and variation in the principles of rate-making, are apt to be controversial and, thus, lead to further uncertainty and costly litigation." (Tr. pg. 111)

10. Mr. Breece

"[H.R. 3165] We believe a denial to the utility of the share in tax benefits of the Investment Credit available to it under present elections will in the long run simply increase the utility's cost of capital and effectively cancel out any immediate reduction in rates." (Tr. pg. 117)

11. Mr. Lederer

"***the simple solution is to detach Federal income tax eligibility of public utilities for accelerated depreciation and the investment tax credit from state rate-making and to recognize that in setting just and reasonable rates, state commissions must take into account capital formation needs of utilities." (Tr. pg. 121)

12. <u>Mr. McIntyre</u>

"***whatever fair rate of return is, whatever gives the utilities return comparable to competitive industries, that should be set by PUC's *** not on a rate base that is increased by adding investment credit to it in an artifical way because the Congress mandates that it be done." (Tr. pg. 131)

Raymond F. Dacek

NINTH SESSION, Wednesday, May 21, 3:00 p.m.

Concurrent Session D-3

NEW DEVELOPMENTS IN ENGINEERING ECONOMICS

CHAIRMAN: Ronald E. White, Ph.D.
Vice President
Foster Associates, Inc.

SPEAKERS: George A. Hazelrigg, Jr., Ph.D.
Director, Systems Engineering
Econ, Inc.

Bob White, Director of off-campus
Engineering and Technical Programs
Western Michigan University

ALTERNATIVE METHODS FOR ECONOMIC EVALUATION OF ELECTRIC ENERGY SYSTEMS AND RATE MAKING

Dr. George A. Hazelrigg, Jr.
Director, Systems Engineering
ECON, Inc.

ABSTRACT

A number of different accounting procedures are presently in use by electric utilities, to evaluate alternative electric energy systems. Only one general accounting framework is legal for determining revenue requirements for rate making. A principal objective of any accounting procedure is to ensure that capital costs are recovered with sufficient return to facilitate raising the necessary funds. Satisfying this objective, however, are a wide variety of capital payback scenarios. Given appropriate returns, investors and stockholders are likely to be indiffferent to the specific accounting procedure chosen, other attributes of the investment held constant. Due to accounting distortions caused by inflation, however, neither the rate-paying customers nor engineering system choices remain unaffected. In particular, under accounting procedures in use today, the apparent cost of new equipment is increased by the high interest rates resulting from inflation, distorting system choices and penalizing customers. Described and illustrated in this paper are a variety of alternative accounting procedures. Attention is paid to how each procedure (1) meets the investors' needs for adequate return on investment, (2) affects the customers' welfare and (3) results in efficient system choices, despite prevailing and forecasted levels of inflation. A detailed example involving a compariosn of coal and nuclear power plants is employed to relate the analyses to actual utility experience.

INTRODUCTION

An objective of an electric utility is to provide electric energy to its customers at a price which is as low as possible while maintaining acceptable levels of safety, reliability and environmental impact. To accomplish this objective, the utilities must construct and operate an efficient, cost-effective system, and they must finance that system with a fair and equitable rate structure. Since it is the customers who ultimately pay for the system and serivce provided, the efficiency of system design and financing is appropriately measured from both the investors' and customers' point of view. Thus, the procedure used for economic evaluation of system alternatives should be the same as the procedure used for determining annual revenue requirements and, hence, rates.

The costs incurred by a utility to provide service can be classified as either expense costs or capital costs. Expense costs are costs associated with items that are fully consumed during a particular accounting period, such as fuel and taxes. Capital costs are costs associated with items that have a lifetime that spans two or more accounting periods, as is the case for most generating, transmission and distribution plant. Expense costs are justifiably recovered by charges made for services rendered during the accounting period in which the expense costs were incurred. The allocation of capital charges across accounting periods, however, is more arbitrary.

There are two distinctly different ways to view charges made to recover capital costs. One view, call it the backward-looking view, is that charges to recover capital costs during the lifetime of the capital item should be sufficient to cover the capital cost plus the accumulated return on the outstanding principal balance. The other view, the forward-looking view, is that charges made during the lifetime of a capital item should be sufficient to cover the replacement cost of the item at the end of its useful life plus accumulated interest on the initial capital investment. This paper examines the first point of view on capital costs, corresponding to current practice in the electric utility industry.

Consider a capital item such as a generating plant with a 30-year life. The backward-looking view states only that sufficient charges should be made against that capital item to recover the capital costs plus accumulated return. It does not specify when, or in what amounts, over the 30 years that payments must be made. Clearly, without further constraint, there is a multitude of possible repayment scenarios. For example:

1. Pay the entire capital cost at the end of the first year plus the interest on the capital for that year.

2. Pay the entire capital cost at the end of the thirtieth year plus the interest on the capital for the entire 30-year period.

3. Make 30 equal annual payments to cover both the capital cost and interest.

If the return to investors (possibly a function of time) is properly chosen, the ability to raise capital should not be affected by the choice of repayment scenario. However, if the customers' rates are to correspond to the cash flows which must be generated to cover the repayment scenario chosen, the customers will most definitely not be indifferent to the repayment scenario chosen. Clearly, for example, the customers would be quite unhappy with the first repayment scenario which would require a drastic rate increase to cover the entire capital cost over only the first year of operation, followed by a rate reduction in successive years, especially if the capital item is to be used to benefit additional new customers after the first year.

It is shown below that, when the effects of inflation are removed, the repayment scenario in widespread use today has a closer resemblance to Scenario 1 than to Scenario 3. It follows that it is desirable to use a repayment scheme which not only meets the return requirements imposed by investors, but which is also likely to be strongly preferred by customers. A few such schemes are defined in this paper and their consequences discussed in detail.

INTEREST, INFLATION AND MONETARY UNITS

Before, proceeding into a discussion on capital repayment scenarios, it is important to understand the concept of interest in the context of the choice and timing of alternate investments. Suppose that there is a potential investor weighing the decision to invest. The investor can either consume his wealth today or he can postpone this consumption to a later date. If he chooses the former, he may spend his money on items such as food, clothing, shelter, art, entertainment and so on. Some of these items, such as food and entertainment may lose their value very rapidly. Others, such as art, can have a comparatively long life and may, in fact, derive added value in time due to scarcity, uniqueness or other properties. If the investor chooses to postpone some of his consumption to a later date, he may do so by placing some of his wealth into an economic activity that can increase the value of his investment for later consumption.

The choice that the investor makes will depend on how he perceives the value of current versus future consumption. If the value of future consumption were increased by returning more value to the investor at some future date than he invests today, he will be more inclined to invest than if the value of future consumption were not enhanced. The enhancement of future consumption is accomplished by returning to the investor a premium or interest on his investment. The higher the premium or interest rate, the more inclined the investor will be to delay consumption into the future and thus the more resources that will be made available to procure capital goods.

It is important, however, to recognize that the above discussion refers to value that consumption has, not to its monetary cost. It must be kept in mind that the transformation of monetary units--dollars, for example--to value, and vice versa, depends on the "buying power" of the monetary unit at any point in time. Thus, as inflation decreases the buying power of the dollar, the investor needs to obtain more dollars simply to break even. It follows that the cost of money (that is, the interest rate that must be paid to investors to cause them to defer present consumption into the future) is closely linked to the inflation rate. In relatively stable economic times, investors demand an interest rate which is roughly two to four percent per year above the inflation rate. In relatively unstable economic times this amount may fluctuate and can, in fact, be negative.

The interest rate demanded by investors, corrected for inflation, is called the real interest rate. If r is the apparent or prevailing interest rate, I the inflation rate and R the real interest rate,

$$(1+r) = (1+R)(1+I)$$

where r, R and I are expressed in per unit. It is interesting to compare current interest rates to those which have occurred over the past 30 years. As Table 1 shows, high apparent interest rates do not necessarily infer high real interest rates.

TABLE 1 APPARENT AND REAL INTEREST RATES

YEAR	AVG. PRIME RATE (r)	INFLATION RATE (I)	REAL PRIME RATE (R)
1950	2.07	5.34	-3.10
1955	3.16	2.67	0.47
1960	4.82	1.32	1.57
1965	4.54	2.46	2.03
1970	7.91	5.08	2.69
1975	7.86	7.43	0.40
1979	12.67	8.90	3.46

A second concept of importance here is that of the monetary unit--the dollar. The dollar is a unit of measure which is used to conveniently effect trade. For example, a utility supplies its customers with electric energy for which, it in return, receives money from its customers. In reality, however, the utility supplies labor, copper, concrete, aluminum, etcetera, which it converts to electricity distributed to its customers who, in return, supply similar goods converted to food, clothing, automobiles, etcetera to the employees and investors of the utility. Dollars are the units by which these trades are effected; they represent only a paper accounting of the underlying physical processes.

Unfortunately, unlike units such as kilograms, watts or seconds, dollars are not currently definable in physical terms independent of time. One day a dollar may buy a given amount of labor, the next day it buys a different amount. Thus, as a result, whenever one does an analysis that involves monetary units, one must be very careful to recognize, in a consistent manner, that they have time varying value.

Consider, for example, the selection of a transformer rating. The physical transformer chosen should not depend on whether the engineer measures the load in VA or in kVA nor on whether ambient air temperature is measured in °F or °C. The appropriate system design is independent of the units used to analyze it. The same should be true when a system is being designed to minimize costs. The minimum cost system is that system which (properly combined) minimizes the sum of the values of the physical resources required to construct and operate the system (within existing institutional frameworks). This physical system should be independent of the monetary units used to analyze it. Due to the way that values of monetary units vary in time, however, it is very easy, and not at all uncommon, to be confused into performing an analysis that yields a result dependent on the inflation rate, that is, the rate at which the monetary unit is changing.

In order to assure that economic analyses are correctly carried out, computations are often performed in constant dollars, that is, dollars of fixed value. Such analyses take the value of a dollar to be that which it was at a given time, say, January 1, 1980, and account for all cash flows in these dollars. Actual cash flows occurring at other points in time are first converted to constant dollars by the use of a time-dependent deflator index. Analysis using constant dollars, however, requires the use of the real interest rate as the cost of money (roughly two to four percent). The analysis that follows focuses on the use of the real versus apparent interest rates.

LEVELIZED COST

A capital cost allocation procedure recommended for use by the utility industry for comparative assessment purposes is the method of levelized cost.* Without going into detail on all of the cost components considered by the procedure, the operative principle is that the cost of a capital item is spread evenly over its lifetime. To do this, one creates an annuity consisting of equal payments made at equal intervals in time, typically annually, which has a present value at the initial operation date of the item equal to the item's capital cost plus interest paid during its construction. The amount of each payment is given by

$$P = C\left[\frac{\frac{r}{n}\left(1+\frac{r}{n}\right)^{Ln}}{\left(1+\frac{r}{n}\right)^{Ln}-1}\right]$$

*Technical Assessment Guide, Electric Power Research Institute, EPRI PS-1201-SR, July 1979.

here P is the payment, C is the capital cost plus cost of money during onstruction, r is the interest rate, n is the number of payments per year and L is he lifetime of the item in years.

One then adds all expense costs expected or incurred during the accounting eriod to the levelized capital cost to obtain the total cost of the good or service rovided by the item. It is inferred that the total cost of the good or service rovided by the item during the accounting period will be borne by the customers erved, in some equitable manner such as proportional to their individual energy onsumptions.

Taking n = 1, the bracketed term in the above equation is referred to as the nnual capital carrying charge (neglecting taxes). Figure 1 shows that the apital carrying charge is strongly dependent on the interest rate. Utilities enerally take their interest rate to be a weighted combination of interest on ebt, dividends on preferred stock and earnings on common stock. At the resent time, the interest on debt and returns to ownership securities is pushing he apparent interest rate, r, into the vicinity of 12 percent. But, as noted bove, these high interest rates are the direct result of high inflation rates hich, in turn, cause rapid devaluation of the dollar.

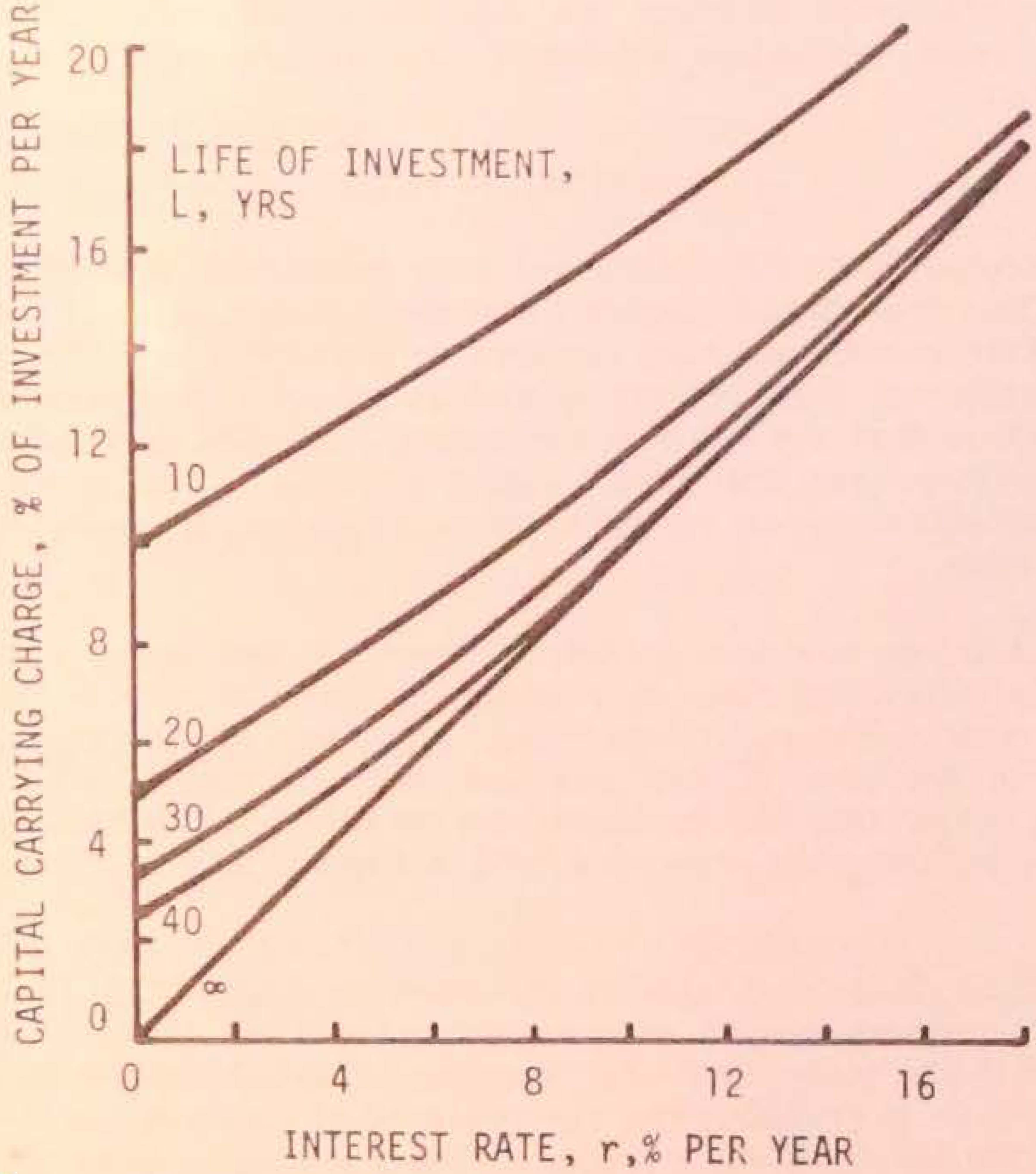


FIGURE 1. LEVELIZED ANNUAL COST OF CAPITAL LESS TAXES

It is important to understand the role of inflation in the computation of the ipital carrying charge and on the payback of the capital investment. Consider o cases involving a relatively stable economy. In the first case, Case A in

Table 2, inflation is taken to be zero whereas, in Case B, it is taken to be ten percent per year. In both cases the real interest rate is taken to be two percent per year. The capital carrying charge for Case B is nearly three times as high as the capital carrying charge for Case A. Note also that the remaining debt diminishes much more slowly in Case B. The key point here, however, is that future payments in Case A are being made with dollars that have as much value as they did in year 1, whereas in Case B the future payments are made in dollars which have greatly diminished value. In fact, a year-30 dollar is worth only 5.73 cents compared to a year-0 dollar. The year-30 payment is only $0.722 million in year-0 dollars, thus carrying less than one-sixth the value. Thus, as Figure 2 shows, the effect of inflation is to raise the interest rate which, in turn, appears to delay repayment of debt, but, in real terms, actually greatly accelerates the debt repayment. This means that, in real terms, under the levelized cost procedure, the users of the capital item would largely pay for the item in its first few years of operation.* Customers added to the system in later years are benefiting at the expense of the earlier customers.

Under levelized cost accounting procedures, high interest rates accompanying high inflation rates result in a strong tendency to disfavor capital intensive activities. It follows that an evaluation procedure such as this yields a result which depends on a parameter, the inflation rate, that does nothing more than change the units in which the analysis is performed. Although this is certainly a valid evaluation procedure one should be fully aware of this characteristic.

LEVELIZED VALUE

An alternative to the levelized cost procedure is the levelized value procedure. This procedure recognizes that the intrinsic value of a capital item is related directly to the resources required to produce it and only indirectly to a monetary measure of those resources, such as dollars. The operative principle of this procedure is that the value of the capital item plus accrued real interest is distributed evenly over the item's useful lifetime. This procedure requires inflating the book value of the item to correspond to its replacement value at any point in time.

Table 3 shows how this procedure works in two cases: Case C in which there is no inflation, and Case D in which the inflation rate is taken to be ten percent per year. The capital carrying charge is calculated using the same equation as in the case of the levelized cost procedure, but using the real interest rate rather than the apparent interest rate. The remaining debt in Case D is found by inflating the remaining debt of Case C by the inflation rate of 10 percent.

Case C of Table 3 is exactly the same as Case A of Table 2. This is because both methods reduce to the same case when inflation goes to zero. Cases D and B are quite different, however. Case D spreads the real capital payback over time in precisely the same manner as Cases A and C. Thus, it can be seen that the levelized value procedure leads to results which are independent of the inflation rate and leads to system choices which are independent of the units in which the analysis is performed.

In the case of the levelized cost procedure, payback of the capital investment is accomplished by means of a sequence of equal payments. In the case of the levelized value procedure, the capital-charge component of electric

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*Capital recovery procedures in actual use are similar, but result in even more accelerated debt repayment.

TABLE 2. EXAMPLES OF LEVELIZED COST PAYBACK

PARAMETER	CASE A	CASE B
INFLATION RATE, %/YR.	0	10
REAL INTEREST RATE, %/YR.	2	2
APPARENT INTEREST RATE, %/YR.	2	12.2
CAPITAL INVESTMENT, $ MILLIONS	100	100
LIFETIME OF CAPITAL, YRS.	30	30
METHOD OF DEPRECIATION	STRAIGHT LINE	STRAIGHT LINE
CAPITAL CARRYING CHARGE, % OF INVESTMENT	4.465	12.599
YEAR 1		
DEPRECIATION, $ MILLIONS	3.333	3.333
PAYMENT, $ MILLIONS	4.465	12.599
INTEREST PART, $ MILLIONS	2.000	12.200
PRINCIPAL PART, $ MILLIONS	2.465	0.399
REMAINING DEBT, $ MILLIONS	97.535	99.601
END-OF-YEAR BOOK VALUE, $ MILLIONS	96.667	96.667
END-OF-YEAR REPLACEMENT VALUE, $ MILLIONS	96.667	106.334
REMAINING DEBT-REPLACEMENT VALUE RATIO, %	100.898	93.668
YEAR 2		
DEPRECIATION, $ MILLIONS	3.333	3.333
PAYMENT, $ MILLIONS	4.465	12.599
INTEREST PART, $ MILLIONS	1.951	12.151
PRINCIPAL PART, $ MILLIONS	2.514	0.448
REMAINING DEBT, $ MILLIONS	95.021	99.153
END-OF-YEAR BOOK VALUE, $ MILLIONS	93.334	93.334
END-OF-YEAR REPLACEMENT VALUE, $ MILLIONS	93.334	112.934
REMAINING DEBT-REPLACEMENT VALUE RATIO, %	101.181	87.797

TABLE 3. EXAMPLES OF LEVELIZED VALUE PAYBACK

PARAMETER	CASE C	CASE D
INFLATION RATE, %/YR.	0	10
REAL INTEREST RATE, %/YR.	2	2
APPARENT INTEREST RATE, %/YR.	2	12.2
CAPITAL INVESTMENT, $ MILLIONS	100	100
LIFETIME OF CAPITAL, YRS.	30	30
METHOD OF DEPRECIATION	STRAIGHT LINE	STRAIGHT LINE
CAPITAL CARRYING CHARGE, % OF INVESTMENT	4.465	4.465
YEAR 1		
DEPRECIATION, $ MILLIONS	3.333	3.333
PAYMENT, $ MILLIONS	4.465	4.465
INTEREST PART, $ MILLIONS	2.000	2.000
PRINCIPAL PART, $ MILLIONS	2.465	2.465
REMAINING DEBT, $ MILLIONS	97.535	107.289
END-OF-YEAR BOOK VALUE, $ MILLIONS	96.667	106.334
END-OF-YEAR REPLACEMENT VALUE, $ MILLIONS	96.667	106.334
REMAINING DEBT-REPLACEMENT VALUE RATIO, %	100.898	100.898
YEAR 2		
DEPRECIATION, $ MILLIONS	3.333	3.667
PAYMENT, $ MILLIONS	4.465	4.912
INTEREST PART, $ MILLIONS	1.951	2.146
PRINCIPAL PART, $ MILLIONS	2.514	2.766
REMAINING DEBT, $ MILLIONS	95.021	114.975
END-OF-YEAR BOOK VALUE, $ MILLIONS	93.334	112.934
END-OF-YEAR REPLACEMENT VALUE, $ MILLIONS	93.334	112.934
REMAINING DEBT-REPLACEMENT VALUE RATIO, %	101.807	101.807

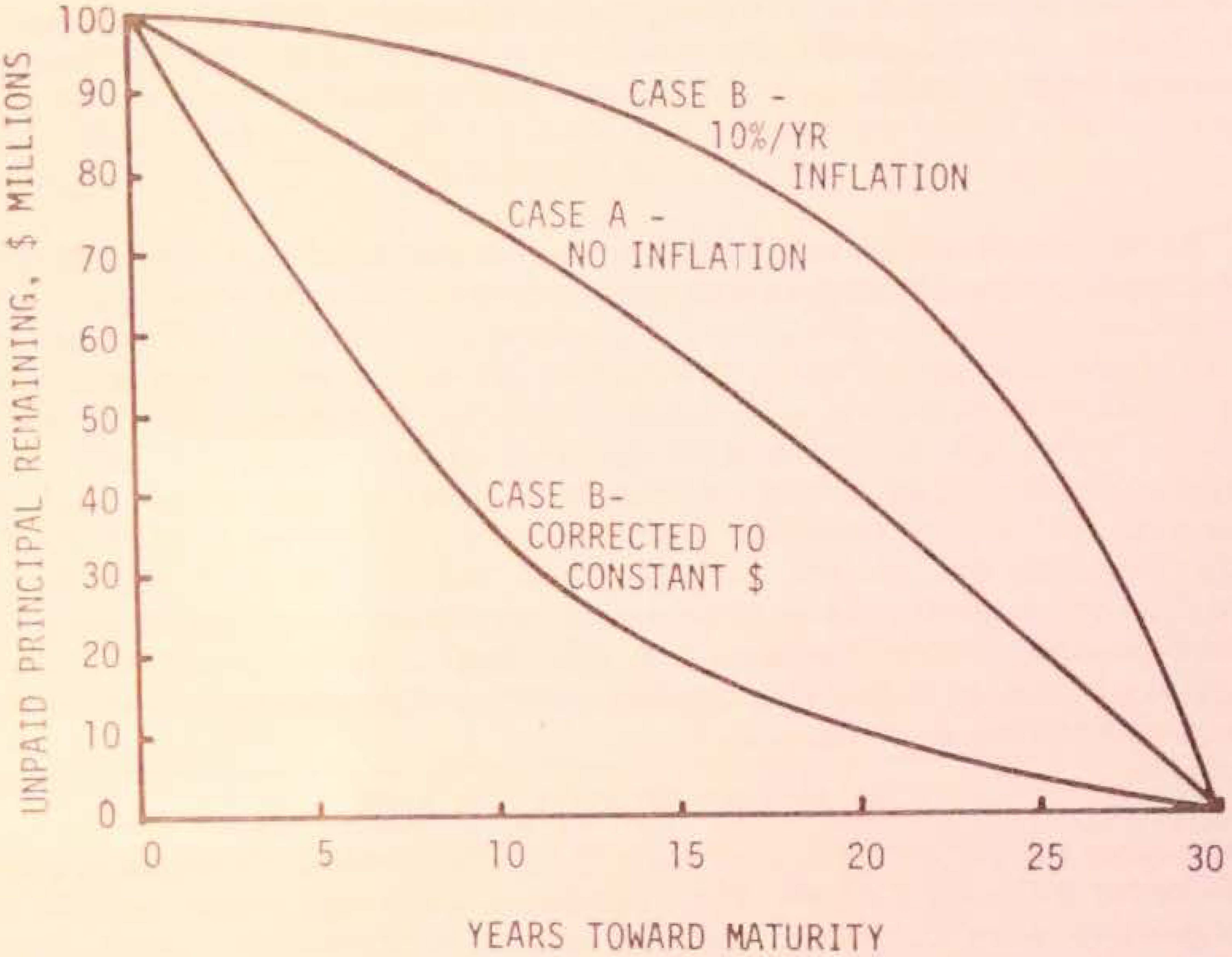


FIGURE 2. THE EFFECT OF INFLATION ON DEBT LIQUIDATION

energy rates would have to be indexed to inflation so that they would automatically increase in proportion to the remaining debt and thus the annual payment.

Whereas the levelized cost procedure corresponds to paying the investor a return on original cost at a rate reflecting inflation and real interest, the levelized value procedure has the effect of retaining the inflation component of return by indexing unpaid principal by the experienced inflation rate. The investors are paid real interest only on this outstanding balance. The accrued interest along with a fraction of the associated principal indexed upward for inflation, is paid to the investor year by year as the capital is recovered.

The implications of this methodology to the customer are as follows: First, in real terms (roughly, for example, the fraction of each customers' income devoted to electric utility payment), utility rates would remain more nearly constant in time. This leads to better customer decisions regarding consumption and conservation since it more closely matches the total cost to society of providing the service consumed. From the point of view of economics, the customer benefits from a uniform year-to-year price rather than a high price one year and a low price the next year. The early customers on a system benefit further from this procedure since they do not subsidize later customers as they do in the levelized cost procedure. Second, the investors should be indifferent to either method since both yield the same real return on investment, but with different timing. In actuality, however, the levelized value procedure protects the investor against future increases in inflation and, hence, may be substantially preferred. Third, the levelized value method is not sensitive to the choice of monetary units in which an economic analysis is performed. Fourth, capital intensive alternatives will not be discriminated against in times of high inflation. These happen to coincide with those generating alternatives which do not rely on oil or gas. Consequently, one result may be reduced energy imports and utlimately better stabilization of the value of the dollar.

OTHER METHODS

A number of other repayment schemes are possible. The only criterion which they must satisfy is the following

$$C = \sum_{j=1}^{L} P_j(1+r)^{-j}$$

where C is the capital cost plus financing cost over the period of construction. P_j is the payment in the jth year, L is the lifetime of the capital item and r is the apparent interest rate. This condition simply states that the present value of the payment stream must equal C.

One set of alternative repayment scenarios simply allows the use of other interest rates falling between the real and apparent rates. In essence, one could use different inflation indices. For example, a wage rate index could be used if the regulators were concerned that the use of a price index could ultimately result in unduly high electric power rates in the case where wages do not keep pace with inflation. A slightly higher interest rate might be used to compensate for uncertainty on the future.

Many utilities recover capital costs on a straight-line basis, that is, they pay an amount C/L against the unpaid principal balance each year. To the principal payment is added annual interest cost on the unpaid principal balance. Under this procedure inflation causes the real repayment of capital cost to occur largely in the first few years of life of the capital item: first, because the equal increments of principal paid each year are actually decreasing amounts in real terms and, second, because the interest rate paid is the apparent rate. This procedure can be corrected for inflation by indexing the unpaid principal balance according to the cumulative effect of inflation and by reducing the interest rate from the apparent rate to the real rate. Under this scenario, the unpaid principal balance is increased each year by the inflation index and reduced by the amount C/L indexed upward by the cumulative inflation index. Later examples detail this procedure more fully.

Many other repayment scenarios can be developed provided they satisfy the above constraint. As long as the rate of return chosen is adequate and other attributes of the investment remain unchanged, the investors and stockholders should be relatively indifferent to which is chosen for implementation. The customers, on the other hand, are not at all indifferent to which procedure is used as it may affect their personal welfares significantly. Thus, the procedure chosen should account for customer preferences as well as investor preferences. The method of capital recovery should also lead to efficient system design choices, independent of the monetary units in which the analysis is performed.

EXAMPLE: NUCLEAR VERSUS COAL COMPARISON

Economic comparison of alternatives plays a major role in developing plans for replacement of current facilities or expansion of capacity. It is instructive to illustrate and compare the effects of three different capital recovery schemes in the context of a realistic example.

The example chosen compares a two-unit coal plant with a two-unit uclear plant. Each plant has a capacity of 2200 MW with an expected life of 35 ears, and goes into full operation in January 1994. Typical capital, fuel, perating and maintenance costs are used. The year-by-year total generation osts (mill rates) are developed for each plant under each of three accounting rocedures.

The first accounting procedure is referred to as the "conventional pro- edure". This represents the method presently in general use by utilities to ecover capital costs. Under this procedure capital is recovered by means of 35 qual annual depreciation payments. In this case, interest on debt and return on quity are paid on the unpaid principal balance at a pretax annual rate of 11.98 ercent. This rate derives from a weighted average of the rates on bonds, ommon stock and preferred stock in accordance with typical values specified in able 4, implying a six percent inflation rate. Depreciation for tax purposes is ouble declining balance and the additional tax savings are credited against npaid balance such that interest or return is not paid on this amount of unpaid rincipal. The tax rate is 51.7 percent. A 10 percent investment tax credit is aken in the first year and spread evenly over the life of the plant at no interest.

TABLE 4. COST OF CAPITAL

TYPE	PERCENT OF CAPITAL	PERCENT RETURN
BONDS	50	10.5
COMMON STOCK	37	14.5
PREFERRED STOCK	13	10.5

The second procedure is referred to as "straight-line indexed". This rocedure is essentially the same as the conventional procedure except that the npaid principal balance is indexed upward at the end of each year by the amount f inflation which occurred during that year. Interest and return are paid at a retax annual rate of 3.74 percent corresponding to the real rates of return given n Table 5. Taxes are based on return on equity and double-declining-balance epreciation of the original cost of the plant. Additional depreciation collected s the result of indexing undepreciated capital with inflation is considered etained interest (inflation component) and is thus non-taxable.

TABLE 5. REAL COST OF CAPITAL

TYPE	PERCENT OF CAPITAL	PERCENT RETURN
BONDS	50	3
COMMON STOCK	37	5
PREFERRED STOCK	13	3

The third procedure, "levelized value", is similar to the straight-line ndexed procedure except that in this procedure the repayment of capital plus nterest on debt and return on equity is made by means of 35 payments of equal value. That is, an annuity of 3.74 percent is created and is indexed upward each year by inflation.

Detailed costs are presented in Tables 6, 7 and 8 for the first, twelfth and thirty-fifth years. An important characteristic of the alternative accounting procedures is that, in the early years, they result in substantially reduced revenue requirements. This reduction is balanced by higher requirements in later years. However, the later-year payments are made in deflated dollars so that they have essentially the same value as the early-year payments.

Figure 3 clearly shows that the conventional accounting procedure greatly accelerates the capital payback, even at a six percent inflation rate. This is shown emphatically in the case of the nuclear plant, the more capital intensive alternative, whose mill rate actually decreases during the first few years. Due to the affect of inflation on results obtained by the conventional accounting procedure, the first-year mill rates for the coal and the nuclear plant are essentially equal, despite the fact that the nuclear plant is more cost effective. The figure also shows that future cost increases using this procedure lag far behind inflation, thus resulting in net real rate reductions for future consumers.

The other two procedures yield results which preserve the real cost effectiveness of nuclear plants over coal over the entire 35-year period, not merely in the latter years. Both procedures follow the trend of general inflation reasonably well, although, as expected, the levelized value procedure is somewhat better. Thus, these procedures lead to mill rate scenarios that are substantially more beneficial to customers than the conventional procedure.

A final comparison between these procedures is given in Table 9, giving the present values of the mill rates summed across all 35 years. Only small differences between the accounting procedures appear, due to differences in taxes. In all cases, the cost effectiveness of the nuclear alternative is preserved. Thus, it is shown that present value of total life cycle costs is a valid comparison index. However, levelized cost of capital added to annual expense is valid for comparison only if there is no inflation. In lieu of levelized costs, levelized value provides a convenient index for cost comparisons that is valid during a period of non-zero inflation.

CONCLUSIONS

In periods of moderate to high inflation, the current method for developing carrying charges for capital items used by many electric utilities needs to be questioned. Currently, the effect is to bias capital payback excessively toward the early years of operation of a new facility. In particular, the cost per MWH for a power plant in constant dollars is significantly higher in the early years of operation than in the later years. Customers served in the early years tend to subsidize those served in the later years.

The levelized value basis for carrying charges is suggested as a means for neutralizing the effects of inflation in the economic evaluation of system investments and the development of rates to pay for new plants. Properly implemented, capital carrying charges based on levelizing the value of annual payments clarify the impact of inflation to all concerned. Customer welfare is improved because real rates would remain constant over time. Investors are attracted by a guaranteed real rate of return and are relieved of the risk associated with the need for anticipating short- and long-term inflation rates. The utility may be better able to meet the cash flow requirements associated with captial intensive projects. Furthermore, the true cost-effectiveness of alternatives such as nuclear generation over coal generation is clearly and convincingly demonstrated.

TABLE 6 FIRST YEAR COST COMPARISONS

SOURCE	ACCOUNTING PROCEDURE: CONVENTIONAL		STRAIGHT LINE INDEXED		LEVELIZED VALUE	
	COAL	NUCLEAR	COAL	NUCLEAR	COAL	NUCLEAR
TOTAL COST, $	3,383,000,000	4,885,000,000	3,383,000,000	4,885,000,000	3,383,000,000	4,885,000,000
CARRYING CHARGE RATE	.24357	.24357	.10653	.10653	.08673	.08673
CARRYING CHARGE, $	823,997,000	1,189,839,000	360,391,000	520,399,000	293,408,000	423,676,000
FIXED O&M PLUS INCURANCE, $	33,000,000	54,000,000	33,000,000	54,000,000	33,000,000	54,000,000
FIXED COSTS MILL RATE	63.5	92.0	29.2	42.6	24.2	35.4
INCREMENTAL O&M MILL RATE	6.9	4.1	6.9	4.1	6.9	4.1
FUEL MILL RATE*	43.7	17.7	43.7	17.7	43.7	17.7
TOTAL MILL RATE	114.1	114.0	79.8	64.4	74.8	57.2
1ST YEAR SAVINGS--NUCLEAR OVER COAL, MILLS/kWh	0.1		15.4		17.6	
1ST YEAR SAVINGS IN REVENUE REQUIREMENT FOR NUCLEAR OPTION OVER CONVENTIONAL ACCOUNTING PROCEDURE, $			669,440,000		766,163,000	

*70 PERCENT CAPACITY FACTOR.

TABLE 7 TWELFTH YEAR COST COMPARISONS

SOURCE	ACCOUNTING PROCEDURE					
	CONVENTIONAL		STRAIGHT LINE INDEXED		LEVELIZED VALUE	
	COAL	NUCLEAR	COAL	NUCLEAR	COAL	NUCLEAR
TOTAL COST, $	3,383,000,000	4,885,000,000	3,383,000,000	4,885,000,000	3,383,000,000	4,885,000,000
CARRYING CHARGE RATE	.12027	.12027	.13670	.13670	.14511	.14511
CARRYING CHARGE, $	406,873,000	587,519,000	462,456,000	667,780,000	490,907,000	708,862,000
FIXED O&M PLUS INSURANCE, $	62,644,000	102,508,000	62,644,000	102,508,000	62,644,000	102,508,000
FIXED COSTS MILL RATE	34.8	51.1	38.9	57.1	41.0	60.1
INCREMENTAL O&M MILL RATE	13.1	7.8	13.1	7.8	13.1	7.8
FUEL MILL RATE*	83.0	33.6	83.0	33.6	83.0	33.6
TOTAL MILL RATE	130.9	92.5	135.0	98.5	137.1	101.5
12TH YEAR SAVINGS--NUCLEAR OVER COAL, MILLS/kWh	38.4		36.5		35.6	
12TH YEAR SAVINGS IN REVENUE REQUIREMENT FOR NUCLEAR OPTION OVER CONVENTIONAL ACCOUNTING PROCEDURE, $			-80,261,000		-121,343,000	

*70 PERCENT CAPACITY FACTOR.

TABLE 8 THIRTY-FIFTH YEAR COMPARISONS

SOURCE	ACCOUNTING PROCEDURE					
	CONVENTIONAL		STRAIGHT LINE INDEXED		LEVELIZED VALUE	
	COAL	NUCLEAR	COAL	NUCLEAR	COAL	NUCLEAR
TOTAL COST, $	3,383,000,000	4,885,000,000	3,383,000,000	4,885,000,000	3,383,000,000	4,885,000,000
CARRYING CHARGE RATE	.04899	.04899	.30277	.30277	.41808	.41808
CARRYING CHARGE, $	165,733,000	239,316,000	1,024,271,000	1,479,031,000	1,414,365,000	2,042,321,000
FIXED O&M PLUS INSURANCE, $	239,284,000	391,555,000	239,284,000	391,555,000	239,284,000	391,555,000
FIXED COSTS MILL RATE	30.1	46.8	93.8	138.9	122.6	180.4
INCREMENTAL O&M MILL RATE	50.0	29.7	50.0	29.7	50.0	29.7
FUEL MILL RATE*	316.9	128.3	316.9	128.3	316.9	128.3
TOTAL MILL RATE	397.0	204.8	460.7	296.9	489.5	338.4
35TH YEAR SAVINGS--NUCLEAR OVER COAL, MILLS/kWh	192.2		163.8		151.1	
35TH YEAR SAVINGS IN REVENUE REQUIREMENT FOR NUCLEAR OPTION OVER CONVENTIONAL ACCOUNTING PROCEDURE, $			-1,239,715,000		-1,803,005,000	

*70 PERCENT CAPACITY FACTOR.

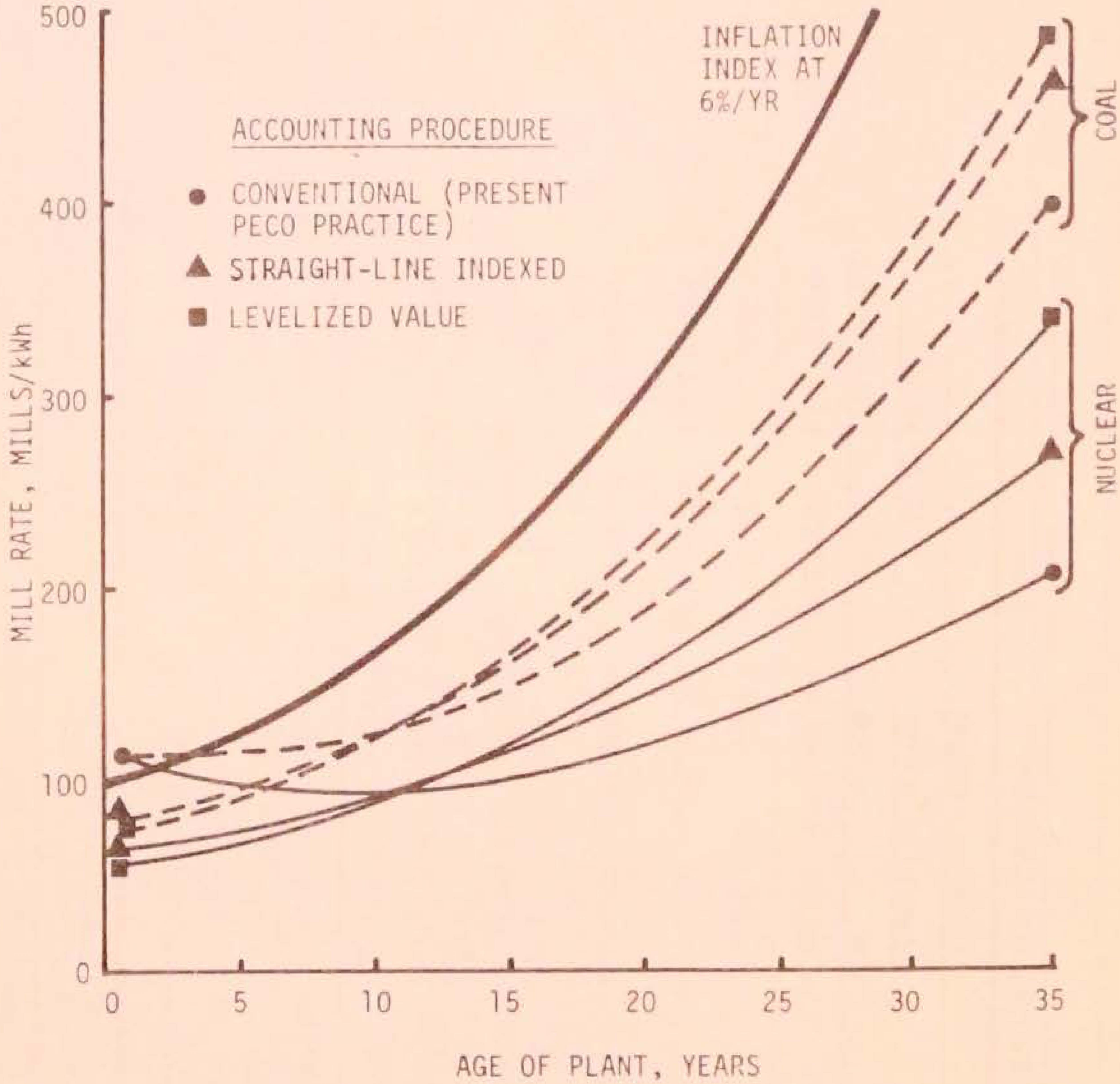


FIGURE 3. MILL RATES FOR COAL AND NUCLEAR PLANTS

Proper handling of inflation in economic evaluations and rate making could result in future rate reductions. To the extent that these reductions reduce inflation, future increases in electricity rates would themselves be reduced. Coal and nuclear generation are both very capital intensive. To the extent that such generation can be installed in this period of high inflation, our nation's dependence on the lower capital intensive generation fueled by gas and oil would be reduced. Such a reduction would diminish our dependence on imported energy and further contribute to the stability of the U. S. dollar.

TABLE 9. PRESENT VALUE* OF ANNUAL MILL RATES

PROCEDURE	COAL	NUCLEAR
CONVENTIONAL	1607.5	1196.9
STRAIGHT-LINE INDEXED	1566.1	1137.4
LEVELIZED VALUE	1587.2	1167.7

*USING A 9.18 PERCENT DISCOUNT RATE CORRESPONDING TO AFTER-TAX COST OF MONEY OF 3 PERCENT AND INFLATION RATE OF 6 PERCENT ANNUALLY.

RANKING CAPITAL INVESTMENT ALTERNATIVES

B. E. White, Assistant Professor
Western Michigan University

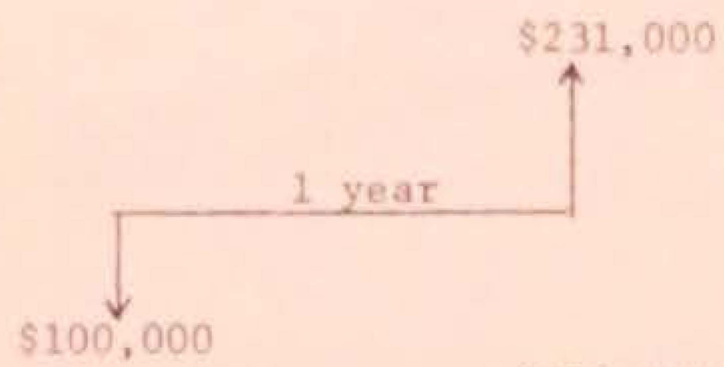
Regulated utilities are part of a capital intensive industry. Most companies have rather large budgets for capital expenditures. Therefore it is important to spend the capital budget in a manner that most effectively contributes to the success of the enterprise. Also, being a regulated industry, utilities do not have unlimited sources of funds. This results in capital rationing, and many projects are not undertaken because of a lack of funds.

There are several methods that can be employed to rank capital investments. Examples of some of these methods are: present worth, rate of return, annual worth, payback, etc. When applied to the same set of projects, these methods may not yield the same results.

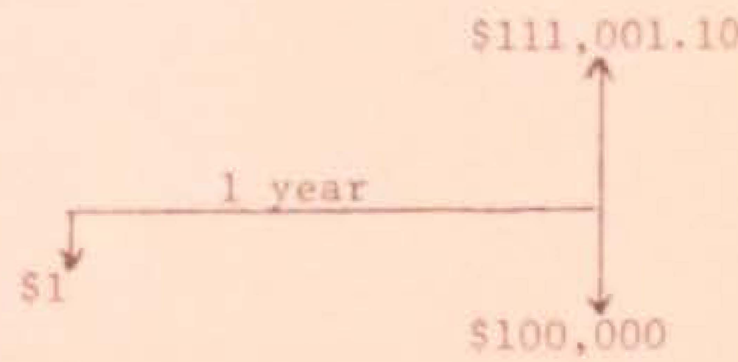
The correct method to use has long been an area of controversy. Many people argue that net present value is best, while others advocate rate of return, annual worth, payback, or other methods.

To illustrate the problem, consider the following cash flow diagrams.

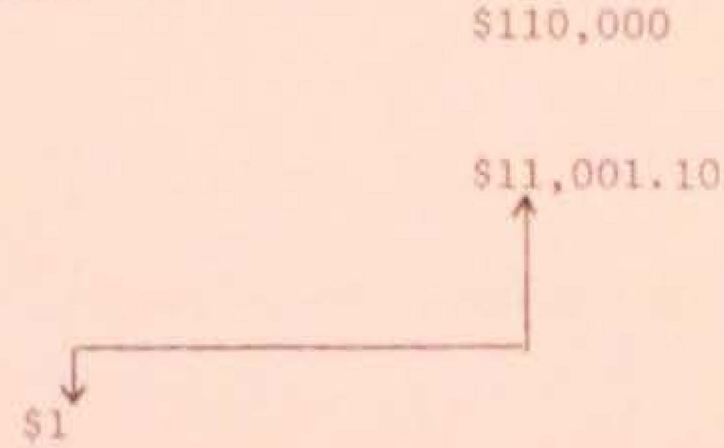
1.



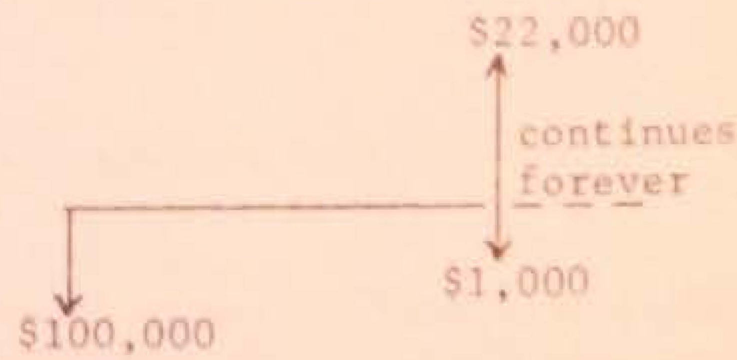
2.



3.



4.



Assume that these cash flow diagrams represent four independent projects, and that the projects must be ranked according to some criteria.

For this example, the projects will be ranked using the following ranking methods.

1. ROR = rate of return
2. PEX = present equivalent excess of revenues over costs
3. PEX/B, where B is the initial investment at time zero
4. AEX = annual equivalent excess of revenues over costs
5. AEX/B, where B is the initial investment at time zero
6. PEB/PEC, where PEB is the present equivalent of benefits, and PEC is the present equivalent of costs
7. PAYBACK = time required to recover initial investment

Using i = 10% and performing the necessary computations yields the following results:

Ranking Method	Project 1	2	3	4	Resulting Ranking
ROR	21%	1,100,010%	1,100,010%	21%	2-3,1-4
PEX	$10,000	$10,000	$10,000	$110,000	4,1-2-3
PEX/B	0.10	10,000	10,000	1.10	2-3,4,1
AEX	$11,000	$11,000	$11,000	$11,000	1-2-3-4
AEX/B	0.11	11,000	11,000	0.11	2-3,1-4
PEB/PEC	0.05	0.11	10,000	1.00	3,4,2,1
PAYBACK	0.83	0.000009	0.000009	4.76	2-3,1,4

Even though the data are obviously contrived to illustrate the point, this example shows that contradictory rankings can result from proper application of various ranking methods. If available funding were either zero or infinite, the ranking procedure is of no consequence. Otherwise, the ranking method employed can affect the portfolio of projects selected.

Computer Model

Working with Dr. G. W. Smith of Iowa State University, a computer model has been developed to assist in studying capital investment ranking methods under various operating conditions.

The model consists of a cash flow simulator that generates both independent and mutually exclusive investment alternatives. Characteristics such as life and cash flow are randomly determined. Optional characteristics of the program include internal rationing of funds, generation of mandatory projects, and inter period borrowing and lending.

The randomly generated alternatives are ranked according to a pre-selected criteria, and accepted for investment until the available funds are exhausted.

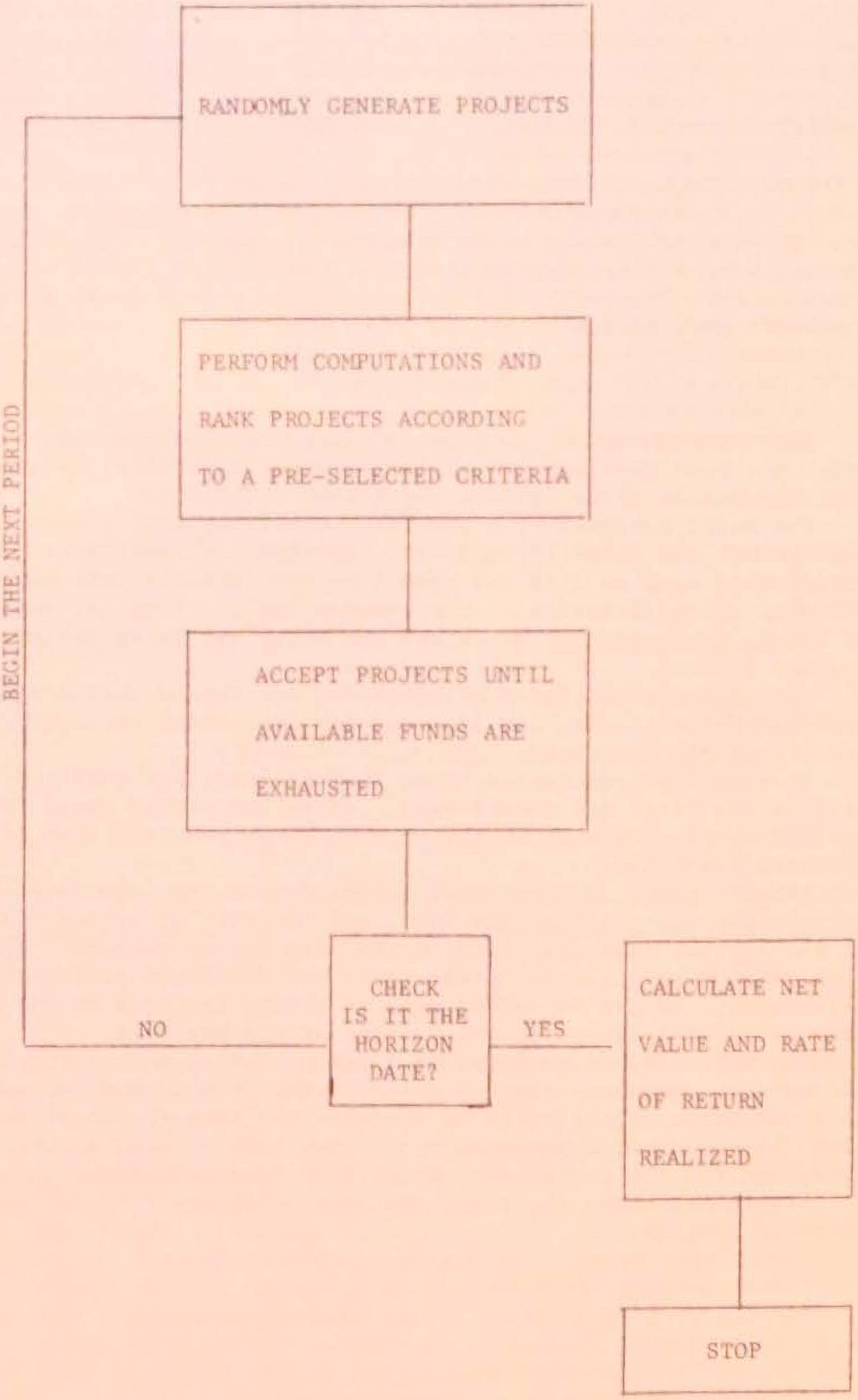
To start the simulation, some initial funds are supplied to the firm in the first and second year. After the second year, future capital budgets consist exclusively of funds returned from previously accepted projects.

After M years of investment activity have been simulated (one cycle), the net value of the firm, and the rate of return realized on the initial funds supplied to the firm are calculated. Since each ranking criteria will tend to select different projects for investment, the net value and rate of return realized at the end of each cycle will depend on the ranking method employed.

One objective is to adopt an inter period project selection matrix that maximizes the net value of the firm at the horizon date. An alternative objective is to maximize the rate of return realized from (1) the initial investment, (2) the cash on hand at the horizon date, and (3) the projected post horizon date cash flows.

Figure one shows the logic and steps that are followed in the computer program.

Figure 1.


RANDOMLY GENERATE PROJECTS
PERFORM COMPUTATIONS AND RANK PROJECTS ACCORDING TO A PRE-SELECTED CRITERIA
ACCEPT PROJECTS UNTIL AVAILABLE FUNDS ARE EXHAUSTED
CHECK IS IT THE HORIZON DATE?
NO
YES
BEGIN THE NEXT PERIOD
CALCULATE NET VALUE AND RATE OF RETURN REALIZED
STOP

The program is constructed to compare the following ranking methods.

AEX = annual equivalent excess of revenues over costs
AEX/B, where B is the initial investment at time zero
PEX = present equivalent excess of revenues over costs
PEX/B, where B is the initial investment at time zero
PAYBACK = time required to recover the initial investment
RANDOM = randomly selecting projects for investment
Incr ROR = Incremental rate of return
Incr AEX/B = Incremental AEX/B
Incr PEX/B = Incremental PEX/B
Incr PAYBACK = Incremental PAYBACK

A brief overview of the program follows.

AN OVERVIEW OF THE CAPITAL BUDGETING SIMULATION

```
INITIALIZE DATA etc.

Do 5 RANKBY = 1, 15    1 = rate of return, 2 = modified ROR,
                       3 = AEX, 4 = AEX/B, 5 = PEX, 6 = PEX/B,
                       7 = PAYBACK etc.
 Do 4 ICYCLE = 1, NC   NC = number of simulation cycles, say 20
  Do 3 NOW = 1, M      Use M = 9 for 9 year simulation etc.
   Do 2 I = 1, NP      NP = number of independent projects per
                            year, say 10
    Do 1 J = 1, MX     MX = number of mutually exclusive alterna-
                            tives in each set.  If MX = 5, then
                            NP*MX = 50 alternatives will be gen-
                            erated each year.
```

Generate MX random numbers uniformly distributed between 0 and 1.
Use random number to simulate input data parameters, for example:

Random number	0-0.125	0.125-0.250	--	0.875-1.00
life (50% with 2 yrs, 50% - 10 yrs)	2	2	--	10
slope (0 = uniform, 1 = gradient)	0	0	--	1
mandatory? (0 = no, 1 = yes)	0	1	--	1

B(J) = J*50,000*1.20**(NOW-1)

1 ROR(J, 1) = 2/5 ** (1 + Random Number) so $\frac{2}{5} > \text{ROR} > \frac{2}{5}^2$

Or, 0.50 ROR 0.08

2 Compute X(K) for each incremental possibility; X(K) is the rate of return, payback period, or whatever was specified by RANKBY. Rank by X(K), then allocate available (AVAIL) funds.

3 AVAIL (for next period) = (CARRYOver cash) + (Sum of cash flows from projects previously accepted) * (Random number <u>normally</u> distributed with mean of 1.0 and SIGMA as specified in initializing data.)

4 Compute and write PEX and ROR for ICYCLE.

5 Compute and write average PEX and ROR over the NC ICYCLES for the RANKBY method.

RESULTS

The initial funds supplied to the firm, ATCF, have a direct influence in determining the level of rationing encountered by the firm in later periods. Table 1 shows the results obtained, averaged over five complete cycles, for three different levels of ATCF.

Table 1. Net Value Achieved Through Use of Various Ranking Methods

Ranking Method	Net Value in Millions — ATCF Level: $2,800,000	$1,300,000	$300,000
AEX	$17.59	$10.31	$2.96
AEX/B	15.74	10.53	3.84
PEX	17.63	10.23	2.76
PEX/B	15.79	10.52	3.73
PAYBACK	14.51	7.81	1.82
RANDOM	12.46	5.99	1.50
Incr ROR	17.85	11.08	3.96
Incr AEX/B	17.87	11.10	3.88
Incr PEX/B	17.95	10.88	3.76
Incr PAYBACK	15.03	6.46	1.85

RANDOM selects investments strictly on a random basis and can be used as a standard against which the other ranking methods can be compared.

The relative effectiveness of a ranking method can be defined as:

$$\frac{\text{Observed Score} - \text{Random Score}}{\text{Best Score} - \text{Random Score}}$$

This effectiveness index can be computed for various levels of ATCF, and the average effectiveness index can be calculated. Table 2 gives the results.

Table 2. Average Effectiveness Index for Various Ranking Methods

Ranking Method	Average Effectiveness Index
Incr ROR	0.994
Incr AEX/B	0.968
Incr PEX/B	0.934
AEX/B	0.828
PEX/B	0.801
AEX	0.724
PEX	0.686
PAYBACK	0.287
Incr PAYBACK	0.219
RANDOM	0.000

Fifty cycles of investment activity were simulated for each ranking criteria at the $1,300,000 ATCF level. Table 3 presents the results.

Table 3. Net Value Achieved by Use of Various Ranking Methods

Ranking Method	Average Net Value in Millions of Dollars
Incr ROR	$10.80
Incr AEX/B	10.80
Incr PEX/B	10.64
AEX	10.20
AEX/B	10.18
PEX/B	10.16
PEX	10.09
PAYBACK	7.57
Incr PAYBACK	6.34
RANDOM	5.69

A paired sample t test was calculated for this data. The results show that for the assumptions and parameters in this model, both Incr ROR and Incr AEX/B yield a net value of the firm that is statistically better than any of the other ranking methods at a significance level of 0.001.

SUMMARY

The method used to rank capital investment alternatives does have an impact on determining the net value of the firm. For the conditions and assumptions of this simulation, the data show that Incr ROR and Incr AEX/B are superior to the other methods studied.

TENTH SESSION, Wednesday, May 21, 3:00 p.m.

Concurrent Session D-4

ANTI-TRUST AND THE REGULATED UTILITIES

CHAIRMAN: George H. Perrine, Retired President
Midwestern Gas Transmission Company
Board of Directors, Iowa State University

SPEAKER: James H. McGlothlin, Esq.
Covington and Burling

ANTITRUST ASPECTS OF THE ECONOMIC OUTLOOK FOR REGULATED BUSINESS IN THE UNITED STATES

James H. McGlothlin

Senior Partner, Covington & Burling, Washington, D.C.
formerly Executive Vice President - Law & Finance
Southern Railway Company

The United States for many years has generally regarded competition as the ideal market control for most business in terms of price, supply and entry. In the purest form of such competition, as defined by economists, no buyer or seller is large enough to affect significantly either the price or supply of the product or entry into the business. Price is established in classic economic theory by the intersection of a demand curve and a supply curve. Entry occurs when profits are high enough to tempt.

The desirability of competition and the wickedness of actions that inhibit or restrain competition has been affirmed by statute in the United States since 1890. In that year the Sherman Act prohibited as illegal "every contract, combination . . . or conspiracy, in restraint of trade or commerce" 1/ and also made it illegal to "monopolize, or attempt to monopolize, . . . any part of the trade or commerce among the several states." 2/ Violation of the Sherman Act by a corporation is now a felony, and a corporation is punishable by a fine of $1,000,000 and an individual by imprisonment for 3 years. 3/ Subsequent legislation, such as the Clayton 4/ and Federal Trade Commission Acts 5/ of the early Wilson Administration and the Celler-Kefauver Antimerger Act 6/ after World War II, attempted to extend and refine the broad principles set out in the Sherman Act.

The provisions of the antitrust laws are not specific. Chief Justice Hughes stated that the Sherman Act has "a generality and adaptability comparable to that

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1/ § 1. 15 U.S.C. § 1, 26 Stat. 209 (1890).

2/ § 2. 15 U.S.C. § 2, 26 Stat. 209 (1890).

3/ §§ 1 & 2, as amended by the Antitrust Procedures and Penalties Act, Pub. Law No. 93-528, § 3, 88 Stat. 1706, 1708 (1974).

4/ 15 U.S.C. § 12 *et seq.*, 38 Stat. 730 (1914).

5/ 15 U.S.C. § 41 *et seq.*, 38 Stat. 717 (1914).

6/ 15 U.S.C. §§ 18 & 21, 64 Stat. 1125 (1950).

found to be desirable in constitutional provisions." 1/ As a result, what the antitrust laws mean and how they should be applied has rested primarily with the courts rather than with the Congress.

The opposite of pure competition is monopoly, in which one firm is the sole supplier, and the price and supply are what that firm decides they will be. The idea that monopoly is wicked came from England into American law. A noted economist has said of the term "monopoly," "[i]n the English language only a few words -- "fraud, defalcation, subversion and sodomy" -- have a greater connotation of nonviolent wickedness." 2/

The modern American law against monopolization has roots that go back to long before the English common law. In 483 A.D. in Constantinople Emperor Zeno commanded "no one may presume to exercise a monopoly of any kind whatever its nature may be."

In later years, Queen Elizabeth the First granted monopolies as rewards to her servants and courtiers on such things as salt, iron, playing cards, tin, bottles, pots and many others. These grants of monopoly eventually came before the courts, and in 1602 Lord Coke ruled against a monopoly in playing cards 3/ and concluded that "the sole trade of any mechanical artifice, or any other monopoly" not only damages "those who exercise the same trade" but it also damages "all other subjects." His grounds for finding such damages were: first, that in a monopoly the price of the commodity will be raised; second, the quality of the commodity will not be so good and merchantable as it was before; and third, the former competitors in this commodity will be without a livelihood and impoverished. 4/

In later years men came to realize that competition was not ideal or even workable in some businesses. Such a business is "a natural monopoly." One reason for such a natural monopoly is that it requires so large and expensive an investment in plant that not more than one company will enter the business. Another reason is that the particular business would be inconvenient for consumers

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1/ Appalachian Coals, Inc. v. United States, 288 U.S. 344, 360 (1933).

2/ J. K. Galbraith, The New Industrial State 179 (2d ed. 1972).

3/ The Case of Monopolies, 6 (Art. XI) Coke 159 (84b); Noy 173 (1602).

4/ Id. at 162-63.

if occupied by more than one or very few enterprises. In the case of telecommunications, not only is a large, expensive plant needed, but also it would be a nuisance for consumers if it were necessary to have several telephones in order to connect with several competing systems. In general, a monopoly cannot exist over a long period without government approval.

A hallmark of monopoly is the difficulty or impossibility of entry. If that difficulty or impossibility is based on a government exclusionary rule, it cannot be dissipated by advances in technology or other developments. On the contrary, if the barriers to entry are not based on government rule, technology may weaken or eliminate them in time. An example of this is intercity telecommunications. The cost of stringing wires or laying underground cable to carry intercity telephone conversations used to be about $90 a circuit. New technology enables telephone communication between cities by a series of microwave towers in line-of-sight with each other and by use of glass fiber transmission lines. This has reduced the costs of an intercity circuit to $13 for original installation and incremental cost of under $1. Naturally, various companies are entering the intercity market. The new entrants do not want to make the heavy investment required for local telephone service.

A natural monopoly that is government-approved usually operates under a statute that substitutes regulation for competition as the primary market control. When a government authorizes a public utility to operate as a natural monopoly, the government not only substitutes regulation for competition as the market control, but it also imposes considerable obligations.

The distinguishing characteristics of business regulation are: (1) control over entry into and exit from the market; (2) control over the market price; (3) control over the quality and conditions of service; and (4) the imposition of an obligation to serve all applicants under reasonable conditions. 1/ These elements of regulation make it plain that complete regulation of a business is antithetical to control by competition of the market for that business. As one court has said, "the whole theory of licensing and regulation by government agencies is based on the belief that competition cannot be trusted to do the job of regulation in that particular industry which competition does in other sectors of the economy." 2/ For many years courts regularly held that the antitrust laws, which promote

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1/ 1 A. Kahn, Economics of Regulation 3, 10 (1970).

2/ Hawaiian Telephone Co. v. FCC, 498 F.2d 771, 777 (D.C. Cir. 1974).

competition, are inapplicable to a regulated business. In a number of instances, the courts held that it was error for a regulatory agency to equate competition with "the public interest." 1/

In my judgment, regulated businesses have not adequately taught the public of the obligations they carry as public utilities. A large company, such as a public utility, is an easy target. It is highly visible, and its charges are a significant part of the cost of living for much of the population. Yet few of the population realize that the price of being allowed to operate as a natural monopoly includes the obligations to serve everyone at a reasonable cost and to have services, rates, and profits controlled. No imaginable cost allocation could justify telephone service five or ten miles into the country to serve a single subscriber or a few subscribers. But it is done. Similarly, no possible cost analysis could justify requiring railroads not to abandon lines which carry so little traffic that trees six inches thick have grown up between the rails. Yet a railroad cannot abandon such a line without permission from the Interstate Commerce Commission.

As future leaders of industry, if your industry is a regulated business, you would serve your company well if you used your influence to see that the public realizes the obligations your company carries and what the company does for the community.

As an example of what this can do, the head of a small water power company in New England did such a good job of making his customers and the community know what his company was and what it was doing that when the Federal Power Act required the company to obtain a permit for continued and expanded operations, his company won the permit over the counter application of the Municipal Gas and Electric Co., although the Act gave a statutory preference to a municipal system. I have no doubt that its municipal system would have won, if the customers and community had not strongly supported the power company because of the work of its president.

It is much less expensive to avoid violating the antitrust laws than to defend a company against charges of violation. In the so-called "big case" the expense to the defendant is astronomical. Not all antitrust violation cases are "big cases," but the drain on the corporation's money and the time of its officers is always significant. 2/

1/ E.g., FCC v. RCA Communications, Inc., 346 U.S. 86 (1953); see also FPC v. Texaco, Inc., 417 U.S. 380 (1974).

2/ Legal and other expenses for defending an antitrust action are deductible as business expenses. Fines imposed (n. cont'd)

For a horror story, the case of United States v. IBM has now been at trial for over ten years. IBM planned to have as a chief witness its chairman, Frank Cary. The government served a subpoena demanding the production of practically every document that referred or related to Mr. Cary. IBM estimated that compliance with this subpoena would take 62,000 man-years and cost hundreds of millions of dollars. When IBM objected to such a sweeping demand, the judge sustained the government. Later IBM announced that it would not call Mr. Cary as a witness, and the government withdrew the subpoena.

To avoid violation of the antitrust laws, you should have both staff and outside attorneys who are knowledgeable in the antitrust field. 1/ One or more members of your legal staff should be experienced in antitrust law, and should have ready access to the decision-makers of the corporation so that his advice can be effective. Your antitrust specialist should, of course, be the kind of person you would otherwise hire -- bright, well-trained, and articulate. Since what you are really looking for is a devil's advocate, you might do well to look first in the Antitrust Division.

Turning now to "antitrust aspects of the economic future of regulated businesses," it is certainly true that regulated businesses are presently under more antitrust attack and are being subjected more to antitrust principles than ever before.

In the past, three approaches gave regulated businesses some protection from the antitrust laws.

The clearest case for protection was a specific exemption in the regulatory statute as to some or all of the activities of the particular regulated business. Such exemptions have existed in the transportation industry, the insurance industry, agricultural cooperatives, and some others.

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in a government antitrust case are not. Treble damages in a private action are tax deductible if the action is not preceded or followed by a criminal action that ends with a finding of guilt either after trial or a nolo contendere plea. In that event, only one third of the treble damages are deductible.

1/ For an excellent discussion of how to use house and outside lawyers to avoid antitrust violations, see Vol. 48 Antitrust Law Journal, Issue I, (1979) published by the Antitrust Section of the American Bar Association. See Castle, "Managing the Relationship with Outside Counsel," 48 Antitrust L. J. 155 (1979).

The Interstate Commerce Act originally contained no express exemption for railroads from the operation of the antitrust laws. Over the years, the railroads developed joint rate bureaus, at which representatives of the railroads and of shippers discussed rates. Since about 70 percent of all freight traffic in the United States moves on more than one railroad, the joint rates shared by the railroads involved are important to both railroads and shippers, and it was seriously believed that joint rates could not be sensibly arrived at without a device such as the joint rate bureaus. However, rate bureaus were attacked as a form of illegal price-fixing in two cases. (Georgia v. Pennsylvania R.R. 1/ and United States v. AAR). After a district court in the AAR case indicated that the railroads were subject to attack for price-fixing through joint rate bureaus, 2/ the Interstate Commerce Act was amended to exempt from the antitrust laws the formation and operation of any agreement approved by the ICC relating to rates, charges, classifications, divisions, allowances or charges, or procedures for the joint consideration thereof. 3/

Some businessmen have a regrettable tendency when given a limited exemption to fall into thinking that the exemption applies to any activity. The railroads twice got into antitrust difficulty by engaging in activities that would otherwise be open to antitrust attack and were not covered by the limited exemption. 4/

A similar exemption was given to motor carriers upon passage of the Motor Carrier Act in 1935 as an amendment to the Interstate Commerce Act, 5/ and truckers, too, used rate bureaus. Also, the Civil Aeronautics Act of 1938 6/ gave antitrust exemption to agreements approved by

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1/ Georgia v. Pennsylvania R.R., 324 U.S. 439 (1947).

2/ United States v. Association of American Railroads 4 F.R.D. 510, 1944-1945 Trade Cas. (CCH) ¶ 57,417 (D. Neb. 1945). In Sept. 1945 the Court denied defendant's motions to strike parts of the complaint and to dismiss.

3/ Reed-Bullwinkle Act of 1948, Pub. L. No. 80-662, 62 Stat. 472, adding 49 U.S.C. 5(b) (1976).

4/ Atchison, T. & S.F. Ry. v. Aircoach Transport Ass'n, 253 F.2d 877 (D.C. Cir. 1958), cert. denied, 361 U.S. 930 (1960). Association of Western Railroads v. Riss & Co., Inc., 299 F.2d 133 (D.C. Cir.), cert. denied, 370 U.S. 916 (1962).

5/ 49 U.S.C. §§ 301-327, 49 Stat. 543 (1935); see also 15 U.S.C.A. § 77c(a)(6) (Supp. 1980), for securities issued by motor carriers.

6/ 49 U.S.C. §§ 1301-1542, 52 Stat. 973 (1938).

the Civil Aeronautics Board as to certain matters. 1/

Critics have urged that the ICC and the CAB have raised the cost of transportation by their regulations, by denial of entry to new companies that wish to operate over routes already being served by existing carriers, and approval of rates alleged to be higher than necessary to provide a fair rate of return.

As for the future, any exemption to the antitrust laws seems to be anathema to the Department of Justice, and it has strongly urged the elimination of such exceptions.2/

The deregulation process, which involves the elimination of antitrust exemption, is well under way in the transportation industry.

The Aircraft Deregulation Act of 1978 3/ narrowed the antitrust exemption and opened up entry into operations over a route already being served by another carrier. 4/ The staff of the Civil Aeronautics Board is

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1/ See Hughes Tool Co. v. Trans World Airlines, Inc., 409 U.S. 363 (1973).

2/ See Part 2 of the "Shenefield" Commission's report "Antitrust Immunities and Economic Deregulation." Report to the President and the Attorney General of the National Commission for the Review of Antitrust Laws and Procedures, ch. 9 (1979). It urges repeal of the statutory antitrust exemptions for railroads, insurance business, and agricultural cooperatives. The approach was that the burden of proof should be on the proponents of antitrust immunities to show "a convincing public rationale for abandoning competition." Ironically, presumably such a showing was the basis for Congress's enactment of the immunities. An official summary of the entire report can be found in 5 Trade Reg. Rep. (CCH) ¶ 50,390 (1979). See also the collection of staff and other papers submitted to the Commission, 48 Antitrust Law Journal Issue 3, Parts I & II (1980).

3/ Pub. L. No. 95-504, 92 Stat. 1705 (1978), amending scattered sections of 49 U.S.C. § 1301 et seq.

4/ The antitrust exemption was narrowed to specific actions that CAB approved as "in the public interest." Each carrier could protect one route, and each carrier could provide nonstop service on one intercity route it had not served before. Section 102 of the FAA of 1958 was amended to require the Board to consider as in the public interest of foreign air transportation: "(4) competition to the extent necessary to assure the sound development of an air transportation system properly adapted to the needs of the foreign and domestic commerce of the United States, of the Postal Service, and of the national defense." 49 U.S.C. § 1302(c).

well-pleased with the operation of the Deregulation Act. Some airlines prophesied that the Act would lead to chaos in the industry and bankruptcy of some airlines, but that has not happened. Numbers of routes that once were served by a single carrier are now served by competing carriers, and there has been a considerable amount of fare competition in contrast with the earlier tendency toward uniform fares.

Deregulation of the trucking industry is in progress. The Senate passed a trucking deregulation bill on April 15, 1980. Motor Carrier Reform Act of 1980 (S. 2245), 126 Cong. Rec. S3639 (daily ed., April 15, 1980). 1/ The Interstate Commerce Commission has indicated both by proposed regulations and by decision that it intends to allow greater entry into the industry and to expand the right to operate over specific routes or in specific sections of the country. Meanwhile, the truck deregulation bill in Congress has the active support of both the Administration and Senator Kennedy. A number of established truckers who have voiced opposition to legislative deregulation may now be in a quandary over whether it would be worse to have the deregulation bill passed or to have it defeated, and then to have the industry deregulated on a non-predictable basis by the ICC.

A number of bills for deregulating the railroad industry have been presented. The Senate, on April 1, passed the deregulation bill called the "Railroad Transportation Policy Act of 1980" (S. 1946). 126 Cong. Rec. S3271-93, S3297-320 (daily ed. April 1, 1980). 2/ All the

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1/ The bill requires approval of applications for entry unless the ICC finds an application to be "not in the public interest." Id. at S3633 (statement of Senator Cannon). It deregulated shipments of processed foods (20% of traffic). It removes the antitrust exemption from collectively setting rates for single line shipments (about 70% of all truck shipments) but did not end it for collectively setting joint truck-truck or truck-rail rates. N.Y. Times, § A, at 2, col. 3.

2/ The dispute over attempts to limit rate increases was resolved by a compromise that allows railroads to increase rates up to five percent a year over rail cost inflation with cumulative increases limited to 14 percent over five years. The ICC will determine a threshold below which there will be no rate regulation. Above the threshold and within the five percent zone the ICC could not suspend a rate. For rates above the zone the ICC could suspend or investigate. As to joint rates, the bill allows a railroad on 45 days' notice to apply a surcharge to a joint rate but must apply it to all of its competing joint routes and to its own competing single line routes. A connecting railroad can cancel the surcharge if it determines that the revenues of the surcharging road are 110 percent or

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bills have in common the reduction or elimination of the antitrust exemption, and would give a railroad some freedom within a specified range to fix rates without interference by the Commission.

Without waiting for any change in the Interstate Commerce Act, the ICC is moving toward some deregulation for railroads. 1/

As for the future, I think deregulation of trucks, railroads, and airlines will grow by statute, agency action, or both. This will include elimination of the antitrust exemptions for railroads, motor carriers and air carriers, and considerably more ease of entry and exit from each industry and from particular routes, with some freedom to establish rates within a reasonable range without governmental approval.

Such deregulation will allow more competition in the transportation industries. It does not necessarily cloud the economic future of all companies in those industries. In a competitive climate, the transportation company that is efficient, aggressive and innovative should prosper as much or more than it did under tight regulation. The less efficient will suffer, probably. All will have less comfort, for they will have to plan and conduct their businesses with advance consideration of antitrust principles. One principle that it is well to remember is that the antitrust laws are intended to protect competition, not competitors. 2/

The second aspect of freedom from antitrust laws for regulated businesses lay in the so-called State Action Doctrine. This was the principle that if a state or its authorized regulatory body ordered an action, obedience to that order could not be considered a violation of the antitrust laws.

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more of its variable costs. As of April 1, the House Commerce Committee had begun hearings on a draft deregulation bill but no bill had been introduced in the House.

1/ In April 1980, in a deregulation action, the ICC exempted eleven more commodity groups in the list of fresh fruits and vegetables. Before the ICC in May 1979 deregulated rail transportation of some fresh fruits and vegetables, railroads for 25 years had been losing such traffic. Since that deregulation railroads have increased produce traffic by at least 14 percent. The ICC has also initiated some flexibility in rates.

2/ Brunswick Corp. v. Pueblo Bowl-O-Mat, Inc., 429 U.S. 477, 488 (1977).

In Parker v. Brown 1/ the plaintiffs tried to enjoin members of a state agency from carrying out a proration program authorized by statute. A unanimous Supreme Court held that the challenged acts could not be the basis of antitrust liability.

Some regulated companies came to believe that anything within a tariff approved by the regulatory commission was within the protection of Parker v. Brown because the utility was required to comply with the tariff.

The 6-3 decision in Cantor v. Detroit Edison Co., 428 U.S. 579 (1976), established that the Parker v. Brown doctrine is not so wide a blanket. Detroit Edison for many years had supplied its customers with free light bulbs, and this practice was incorporated in a tariff. A private seller of light bulbs sued, alleging abuse of monopoly by restraining competition in light bulbs. The district court gave judgment summarily for the defendant on the basis of the tariff. The Supreme Court reversed. Mr. Justice Stevens, for a four-man plurality, said that free distribution of light bulbs could not have initially been required by the regulatory agency, since Detroit Edison had started the practice before the Michigan Public Utility Commission was established. The Court also rejected Detroit Edison's argument that there was such a pervasive scheme of regulation that exemption from the antitrust laws should be implied. The Court concluded that the regulatory scheme dealt essentially with "the distribution of electricity," and that the distribution of light bulbs was outside the scope of that scheme. It concluded that the distribution of light bulbs was unregulated, and that there was no implied antitrust immunity as to that activity.

The decision can be interpreted as creating an unworkable distinction for companies operating under tariffs between things in the tariff that were initiated by the regulated company and acquiesced in by the regulatory commission and those that reflect the "real" wishes of the state legislature. On this approach, because the Michigan legislature had failed to indicate explicitly that it wanted light bulb sales regulated, the fact that the Michigan Public Utility Commission had been doing so for years did not place the light bulb tariff beyond the reach of the Sherman Act. A more reasonable interpretation is that the statutory regulatory scheme, though broad, did not relate to this activity. Thus it is of paramount importance for each regulated industry to analyze carefully which of its activities are, or are not, regulated. 2/

1/ 317 U.S. 341 (1943).

2/ It has been suggested that in proposed communications legislation both AT&T and Comsat should be required to form a separate subsidiary to perform all non-regulated activities, and that the parent be required to deal on the same basis with its subsidiary and competitors of the subsidiary.

In March 1980, the Supreme Court clearly explained the holding in Cantor v. Detroit Edison and the current status of the state action doctrine. Mr. Justice Powell, speaking for an unanimous Court said that in the Cantor case "a majority of the Court found that no antitrust immunity was conferred when a state agency passively accepted a public utility's tariff." He also said that prior decisions "establish two standards for antitrust immunity under Parker v. Brown. First, the challenged restraint must be 'one clearly articulated and affirmatively expressed as state policy'; second, the policy must be 'actively supervised' by the state itself." Applying these tests, the Court held that the antitrust laws made invalid a statutory fair trade pricing system for wine in which wine producers filed prices that all were required to follow, but the state did not fix prices or review their reasonableness. California Retail Liquor Dealer's Ass'n v. Midcal Aluminum Inc., No. 79-97, Sup. Ct. March 3, 1980.

For the economic future of a utility, it cannot assume that because there is a regulatory statute, every one of its activities is so regulated as to be immune from antitrust attack. Painstaking analysis is required.

If these precautions are taken, I doubt that attacks on actions pursuant to an agency order are a dire threat to economic progress. Attacks may come and be a headache, but they need not be disastrous.

In at least one area compliance with agency orders may create liability. A "squeeze-rate" situation exists when an electric utility has wholesale rates so much higher than retail rates that its wholesale customers cannot compete with the utility in retail markets. The wholesale rates are set by the Federal Energy Regulatory Commission (and its predecessor the Federal Power Commission), and the retail rates by a state agency, but actions of the agencies may not be synchronized or coordinated. The Supreme Court has held that the Federal Power Commission in acting on a request for an increase in wholesale rates should consider allegations of wholesale consumers that the proposed wholesale rates are discriminatory and noncompetitive when considered in relation to the company's retail rates. 1/ It did not hold that retail rates must control wholesale rates. It is possible for a regulated company to apply for and get a wholesale rate that is reasonable and then have a state agency impose retail rates below that level. It seems only sensible that a regulated company that complied with the action of both agencies should not be penalized under the antitrust laws.

1/ FPC v. Conway Corporation, 426 U.S. 271 (1976).

However, in City of Mishawaka v. American Electric Power Co., 1/ the District Court awarded the plaintiff cities $12 million damages ($4 million trebled) and issued an injunction on a finding of a price squeeze in violation of section 2 of the Sherman Act. 2/ The Seventh Circuit vacated the award of damages, and the injunction, but affirmed as to liability. 3/

Although this is an ominous holding, there is hope that such squeeze rate cases can be successfully defended on the basis that the rates were reasonable on a cost basis, that in some cases electricity was available from other sources, and that there were no measurable competitive damages. 4/ Also, the Federal Energy Regulatory Commission in a series of decisions and by proposed rules has made it simpler to prove that "squeeze rates" exist. 5/ Commentators have strongly attacked these actions.

1/ City of Mishawaka v. AEP, 465 F. Supp. 1320 (N.D. Ind. 1979), aff'd ___ F.2d ___, 1980-1 Trade Cas. (CCH) ¶ 63,193 (7th Cir. 1980).

2/ Id., 465 F. Supp. at 1341-44.

3/ ___ F.2d ___, 1980-1 Trade Cas. (CCH) ¶ 63,193 at 77,929-33 (7th Cir. 1980). The Circuit Court held that the utility's frequent applications to the federal agency for increased rates that would go into effect promptly, subject to refunding, were illegal and not protected by the Noerr-Pennington doctrine. This holding may cause reversal in the Supreme Court. The Circuit Court affirmed the holding that Parker v. Brown did not immunize the defendant. It held that damages were not the difference between the rates but had to be shown by actual proof of competitive damage. It also vacated the District Court's injunction against applying for higher wholesale rates that might become effective before comparable higher retail rates.

4/ The defenses and authorities are well presented in Avery, "Price Squeeze and Utility Rates," Proceedings of Iowa State University Regulatory Conference, p. 305 et seq. (1979).

5/ Boston Edison Co., Opinion No. 53 (July 31, 1979) held there was a rebuttable presumption that competition exists between an electric utility and its wholesale customers. Connecticut Light and Power Company, Order Reversing Administrative Law Judge's Dismissal of Price Squeeze Allegations for Failure to Prove a Prima Facie Case (Aug. 20, 1979) held that geographical proximity and the wholesale customer's ability to serve were enough to raise the presumption. In Florida Power & Light Company, Opinion No. 57 (Aug. 3, 1979), the Commission used a classic Sherman Act analysis of monopoly power and abuse of it to reject amendments to tariffs that would restrict the availability of

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The third aspect of protection for regulated industries from the antitrust laws lay in implied exemption. This is the concept that by establishing regulation as the method for control in an industry, the legislature had rejected competition as the market control, and that since the antitrust laws were designed to protect competition they were necessarily inapplicable. Logically, this concept has no basis as to any phase of the industry's activity that is not regulated, and the concept came to be thought of as "pervasive regulation"; _i.e._, if _all_ of an industry's activities are regulated, _none_ of them are subject to the antitrust laws. For many years, this seemed to be firmly established: few antitrust actions were brought against regulated industries, and courts usually held that extensive regulation made application of the antitrust laws inappropriate. 1/

This happy situation for regulated businesses appeared to change with the decisions of the Supreme Court in _Gulf States Utilities Co._ v. _Federal Power Commission_, 411 U.S. 747 (1973) 2/ and _Otter Tail Power Co._ v. _United States_, 410 U.S. 366 (1973). In the _Otter Tail_ case, municipal utilities attacked the refusal of the regulated electric generating company to supply them with power. The Supreme Court in a 4 to 3 decision decided that Congress in

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firm wholesale service. In _Southern California Edison Co._, Opinion No. 62 (Aug. 22, 1979), the Commission announced a policy of phasing proceedings on price squeeze allegations after all cost of service issues as to both types of rates had been resolved. In _Commonwealth Edison Company_, Opinion No. 63 (Sept. 14, 1979), the FERC indicated it would use rates of return on the different rates in dealing with price squeeze allegations. Then the FERC moved to change its regulations to reflect the principles and procedures noted above, _Notices of Proposed Rulemaking_ in Dockets RM 79-79 and RM 79-80, 44 Fed. Reg. 67154 and 67158 (Nov. 23, 1979).

1/ Keogh v. Chicago & Nw. Ry., 260 U.S. 156 (1922); Gordon v. New York Stock Exchange, Inc., 422 U.S. 659 (1975); United States v. National Ass'n of Securities Dealers, Inc., 422 U.S. 694 (1975); Pan American World Airways, Inc. v. United States, 371 U.S. 296 (1963); Silver v. New York Stock Exchange, 373 U.S. 341 (1963); Hughes Tool Co. v. Trans World Airlines, Inc., 409 U.S. 363 (1973).

2/ In _Gulf States_, the Court held 6 to 3 that when the FPC is passing upon a public utility's application to issue a security, the Commission must consider the issue's anticompetitive effect in determining whether it is "compatible with the public interest." _Id._ at 756; see Federal Power Act, § 204(a), 16 U.S.C. § 824c.

passing the Federal Power Act had expressly rejected the idea of providing pervasive federal regulation for electric generating companies. On that basis, it held that the antitrust laws did apply to the generating companies' refusal to supply power to the municipal utilities, and that such refusal was a violation of the antitrust laws as an abuse of monopoly power. Although the decision was a breakthrough, it did not mean that the antitrust laws apply to a situation in which there is pervasive regulation of a business. The Supreme Court in later decisions so held. 1/ However, the Supreme Court has often rejected the argument that antitrust laws should not apply to a particular regulated business, either on the ground that the regulation was not pervasive or that the activity attacked was not central to the regulatory scheme. 2/ Also, even in decisions that permitted some application of the antitrust laws to a regulated business, the Supreme Court has held that application of those laws must take into account the existence of regulation that affected the structure and operation of the market. 3/

Attacks upon regulated business both by government and in private actions have increased greatly during the last 10 to 15 years. The most striking example is the government's case against the American Telephone & Telegraph Company in the District of Columbia, in which the relief sought would restructure the telephone system in the United States. Former Attorney General Bell suggested that a matter with such drastic impact upon the nation should be dealt with as a legislative matter by Congress rather than by the decision in a court case. His suggestion has not been adopted. AT&T's attempts to have the case dismissed on the ground of pervasive regulation of the telecommunications industry have not been successful. Also, private suits against regulated business have increased, relying upon allegations that action of the business required or permitted by regulation was a violation of the antitrust laws.

1/ City of Lafayette v. Louisiana Power & Light Co., 435 U.S. 389 (1978); United States v. National Ass'n of Security Dealers, Inc., 422 U.S. 694 (1975); Gordon v. New York Stock Exchange, Inc., 422 U.S. 659 (1975).

2/ Georgia v. Pennsylvania R.R., 324 U.S. 439 (1945); United States v. Radio Corp. of America, 358 U.S. 334, 348-50 (1959); United States v. Philadelphia National Bank, 374 U.S. 321, 352 (1963); Silver v. New York Stock Exchange, 373 U.S. 341, 360-361 (1963); California v. F.P.C., 369 U.S. 482, 485 (1962).

3/ United States v. Marine Bancorporation, Inc., 418 U.S. 602 (1974); Goldfarb v. Virginia State Bar, 421 U.S. 773 (1975).

In considering the threat to regulated businesses rom antitrust attacks upon the ground of monopolization, t is necessary to remember how the Supreme Court has de- ined that violation. The Court's most frequently quoted efinition of monopoly power is "the power to control rices or exclude competition." 1/

The mere existence of monopoly power is not il- egal under the Sherman Act. 2/ Illegality stems from the willful acquisition or maintenance of that power as dis- inguished from growth or development as a consequence of a uperior product, business acumen, or historic accident." 3/ his description is a condensation of Judge Wyzanski's arlier explanation in the Shoe Machinery case that in a onopolization case

> "[T]he defendant may escape statutory liability if it bears the burden of proving that it owes its monopoly solely to superior skill, superior products, natural advantages (including accessibility to raw materials or markets), economic or technological efficiency (including scientific research), low margins of profit maintained permanently and without discrimination, or licenses conferred by, and used within, the limits of law (including patents on one's own inventions, or franchises granted directly to the enterprise by a public authority)." 4/

/ United States v. E. I. duPont deNemours & Co., 351 U.S. 77, 391 (1956) (emphasis added). While this is sometimes ut in the conjunctive, it makes little difference since the wo powers are complementary. The Court continued, "[p]rice nd competition are so intimately entwined that any discus- ion of theory must treat them as one. It is inconceivable hat price could be controlled without power over competi- ion or vice versa." Id. at 392.

/ Senator Philip Hart's "Monopolization Reform Act of 976" (S. 3429, 122 Cong. Rec. 13872-73 (1976)) was not nacted. It would have radically changed the law. Senator art said that the Act would make the appropriate standard or the offense of monopolization "not abuse or use [of onopoly power], but rather whether or not the defendant as the power to control price or exclude competitors." 22 Cong. Rec. 13874 (1976). In effect, this emphasis on arket structure would often have made simple bigness a iolation of law.

/ United States v. Grinnell Corp., 384 U.S. 563, 570-71 966).

/ United States v. United Shoe Machinery Corp., 110 F.

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As I read it, this means that a regulated company operating under a license or permit is a lawful monopoly.

The Otter Tail decision and others show that even a lawful monopoly may be guilty of illegal monopolization either because regulation was not so pervasive as to imply an exemption, or because the particular activity is not regulated.

When a regulated business is held subject to the antitrust laws, it is living in the worst of possible worlds. The regulatory agency either permits or requires the regulated business to be and act in ways that are classic violations of the antitrust laws if done by an unregulated business: e.g., monopoly of supply, building new capacity to supply anticipated future demand, 1/ and in some cases agreement upon price.

The essential and basic conflict between the regulation of business and reliance upon competition to control the market would be made much worse if the so-called "Competition Improvements Act of 1979" (S. 382), introduced by Senator Kennedy, becomes law. 125 Cong. Rec. S1272-73 (daily ed., Feb. 7, 1979).

The bill declares that Congress finds, inter alia, that "this Nation is founded upon and committed to a private enterprise system and a free market economy . . . ;" and that "Federal agencies have taken actions which are more anticompetitive than necessary to achieve statutory goals." The bill then declares it is "the purpose of this Act to reaffirm that the fundamental national economic policy of the United States is free and open competition." It seeks to do so by:

> "(1) minimizing anticompetitive behavior in regulated industries;
>
> (2) establishing procedures that strengthen and facilitate the application of antitrust and procompetitive policies by Federal agencies; and

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Supp. 295, 342 (D. Mass. 1953), aff'd per curiam, 347 U.S. 521 (1954) (emphasis added).

1/ Judge Learned Hand in the Alcoa case (United States v. Aluminum Co. of America) said that consistent expansion of capacity by an unregulated monopoly to meet anticipated demand was clearly illegal monopolization. See 148 F.2d 416, 431 (2d Cir. 1945). But a regulated business has an obligation to provide supply to all.

(3) enabling Federal agencies better to restore, maintain, and protect open and vigorous competition in the marketplace." (Section 2(b)).

Section 3(a) of the bill attempts to effect this policy. It reads:

"(a) Notwithstanding any other provision of law, no Federal agency shall take any action, the effect of which may be substantially to lessen competition, to tend to create a monopoly, or to create or maintain a situation involving a significant burden on competition, unless it finds that -

(1) such action is necessary to accomplish an overriding statutory purpose of the agency;

(2) the anticompetitive effects of such action are clearly outweighed by significant and reasonably certain benefits to the general public; and

(3) the objectives of the overriding statutory purpose cannot be accomplished in substantial part by alternative means having lesser anticompetitive effects."

It appears that all three of the conditions must be met to justify a rule that may substantially lessen competition or create or maintain a situation involving a significant burden on competition.

Section 4 of the bill requires that each independent regulatory agency, 1/ in addition, consult with the Attorney General and establish procedures by which the Attorney General "will be notified of important pending agency action subject to section 3(a)." (There are no guidelines for determining which actions are "important.") This provision is included despite the substantial public disclosure requirements already attending contemplated agency actions.

Where the Attorney General is of the opinion that the requirements of section 3(a) have not been met, the independent agency must convene a hearing or other "appropriate proceeding" if a hearing has not already been held. Section 4(c).

The Attorney General and the FTC may appear as parties of right in any section 3(a) proceeding, thus giving them full rights of appeal. They "may utilize any and all

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1/ Defined as the ICC, FERC, FCC, SEC, CAB, FMC, NRC and FTC. Section 8(c).

powers conferred upon them by any other provision of law . . . in carrying out their responsibilities under the Act." 1/

In the event of judicial review of a 3(a) proceeding, the burden is placed on the agency (the defending party) to establish by substantial evidence that the requirements of section 3(a) have been met. If a judicial challenge to the agency action succeeds, the agency may be liable for the costs of the litigation including expert and attorneys fees if the action "served an important public interest" and the challenger lacks sufficient resources or its economic interest is small in comparison to the costs of effective participation in the litigation. See section 5.

Under section 6, each Federal agency must consult with the Attorney General and the FTC to "identify and develop . . . methods and procedures, which will insure that antitrust laws and policies, and the promotion of competition, will be facilitated and enhanced in planning, in decisionmaking, and in other activities."

Each agency must review its statutory authority to determine "whether there are any deficiencies or inconsistencies which may prevent full compliance with the purpose of this Act" and make recommendations for any necessary measures to "maximize" the policies of the Act. It is possible that this provision will be interpreted as a directive to identify "overriding statutory purposes" which authorize anticompetitive regulation and to suggest legislation which will eliminate such "overriding" policies.

Each agency must review and modify prospectively its rules, regulations, policies, practices and procedures so as to have them conform to the purposes, policies and provisions of the bill.

The FTC is obliged to report annually "on the degree to which Federal agencies have complied with the purposes of this Act by fostering substantial and effective competition in this economy" and making recommendations for areas of priority consideration.

The bill is a further extension of the efforts of the FTC and of former Assistant Attorney General for Antitrust John Shenefield to inject competitive considerations in all kinds of federal agency deliberations. 2/

1/ Section 4(d).

2/ The bill was endorsed by the National Commission for the Review of Antitrust Laws and Procedures. This Commission, which operated during most of 1978, was headed by Mr. Shenefield, and was staffed entirely by persons drawn from the Antitrust Division of the Justice Department. See

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The bill contradicts the doctrine that for a regulated business the regulation rather than competition should be the controlling factor, and in effect reverses the Supreme Court decisions that it is error for a regulatory agency to equate the public interest with competitive pricing or other competitive considerations.

Also, the bill would reverse the traditional presumption of correctness of an agency decision and place upon the agency the burden of proving that it had complied with the bill in making its decision.

As for the future, I believe that the defense of implied exemption by pervasive regulation will be steadily weakened as deregulation reduces or eliminates the basis for the defense. This seems to be happening with communications in the numerous decisions of the Federal Communications Commission that one phase after another of the industry is opened to competition, and it is happening in the transportation industry. The movement can be expected to spread to other industries now regulated.

Nevertheless, the best hope for regulated business to have protection from the antitrust laws appears to be to revive and expand the concept that pervasive regulation makes the antitrust laws inapplicable. 1/ Several factors will strongly affect the success of such an attempt, and none of them can be confidently predicted.

The first factor is the makeup and philosophy of the Supreme Court. The importance of the membership of the Court is best illustrated by the difference in the approach to antitrust matters between the Warren Court and the present Burger Court. During the Warren Court, there was a block of four Justices (Justices Black, Douglas, Brennan, and Marshall) who could be relied upon to read the antitrust laws broadly and to enforce them vigorously. The Warren Court was so consistent in sustaining judgments enforcing the antitrust laws that Justice Stewart in a bitter dissent asserted that the only consistency in antitrust merger decisions in the Supreme Court was that "the Government always wins." 2/ By 1976, the Warren Court had come into being in the sense that four Justices appointed by Presidents Nixon and Ford formed a substantial minority and

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eport of the National Commission, adopted Jan 16, 1979, hapter 15", reprinted in 125 Cong. Rec. S1274-75 (daily ed., eb. 7, 1979).

/ In the current political climate, hopes for legislation roviding express exemption from the antitrust laws for pecified industries appear to be only wishful thinking.

/ See United States v. Von's Grocery Co., 384 U.S. 270, 01 (1966).

needed to add only one vote to become a majority. Indeed, during the 1977 term of the Supreme Court the defendant came out on the winning side of every antitrust case decided on the merits. 1/ The present court has overruled or limited a few of the decisions of the Warren Court in antitrust matters, notably the Schwinn decision which held that territorial restraints were a per se violation. 2/ However, the impact of the Burger Court upon antitrust law has not been as extensive as it might have been, for two reasons. The first is that the decisions of the Burger Court on antitrust matters have usually been limited to the precise factual situation before the Court. The Court has not taken the opportunity to make broad decisions that would greatly limit or overturn broad decisions by the Warren Court. Also the Burger Court, for some reason, has refused to review some important antitrust decisions by the lower courts which would have given it opportunities to clarify or limit holdings of the Warren Court.

A dramatic example of this is the Court's recent refusal to grant certiorari to review the decision of the Second Circuit in Berkey Photo, Inc. v. Eastman Kodak Company. 3/

1/ One commentator noted that this was "as newsworthy as the proverbial story of a man biting a dog." Handler, "Changing Trends in Antitrust Doctrine: An Unprecedented Supreme Court Term," 77 Colum. L. Rev. 979, 980 (1977).

2/ Continental T.V., Inc. v. GTE Sylvania Inc., 433 U.S. 36 (1977) (overruling United States v. Arnold, Schwinn & Co., 388 U.S. 365 (1967)).

3/ Berkey, a camera manufacturer and photo-finisher, charged that Kodak abused monopoly power in film in numerous ways, including developing a new film (Kodacolor II) and a new camera (the 110 series) that could use only that film, without any notice to Berkey; and by developing a new type of flash in cooperation with Sylvania and GE under a contract that kept the flash secret until marketed. The District Court held for the plaintiff on most counts. Although it set aside several damage awards by the jury, it awarded damages of over $70 million, plus attorneys' fees and costs. 457 F. Supp. 404 (S.D.N.Y. 1978). The Second Circuit reversed as to a number of issues, reversed or remanded as to damages, and vacated awards for attorneys' fees and costs. 603 F.2d 263 (2d Cir. 1979). It held, however, that the flash bulb development in secrecy may have violated Section 1 of the Sherman Act, and that with respect to the new film and camera, Kodak violated section 2 by using its power over films and cameras to get an advantage in photo finishing and photo finishing equipment. Id. at 279-85, 304. The Supreme Court denied certiorari, with three Justices dissenting. A dissenting opinion on a certiorari matter is rare, but Rehnquist and Powell filed one expressly attacking the Court's unwillingness to review important antitrust cases. Berkey Photo, Inc. v. Eastman Kodak Co., 100 S. Ct. 1061 (Feb. 19, 1980).

Because the Burger Court makes its antitrust decisions on narrow grounds and refuses to review important new antitrust cases, the lower federal courts, the Federal Trade Commission, and the Antitrust Division have a tendency to apply antitrust laws as if there had been no change in the Court and no decisions limiting those of the Warren Court.

The makeup of the Court is likely to change further during the next four years due to the age and health of its members. How such changes will affect the Court's attitude is impossible to predict because we do not now know what the next President's economic philosophy will be, and a person appointed to the Supreme Court on occasion has developed a judicial philosophy quite different from what the appointing President expected.

Of the present members of the Court, Mr. Justice Brennan, who is 74, and Mr. Justice Marshall, who is 72, have both been in ill health. They were both parts of the Warren Court and usually voted for a broad interpretation of the antitrust laws. The other two oldest members of the Court are Mr. Justice Powell at 73 and Chief Justice Burger at 72. Both were Nixon appointees and tend to interpret the antitrust laws more narrowly. The same is true of another Nixon appointee, Mr. Justice Blackmun, who is 71 this year.

The second factor is the skill and persuasiveness of the attorneys representing regulated businesses that are attacked under the antitrust laws. It is well settled that exemption from the antitrust laws is not to be implied lightly, and that partial repeal of such a law (which amounts to the same thing) is to be rarely found, absent some expression to that effect in the legislative history of the regulatory statute. 1/

I certainly do not mean to imply that any of the attorneys who defend regulated businesses against antitrust attack are not highly competent. My point is that the establishment of implied immunity is an extremely difficult task.

The third factor is the course of future legislation and administrative change in regulations. In several areas, active consideration has been and is being given to legislation that would lessen control of the business by the regulatory agency and open some aspects of the business to competition. At the same time, important Federal agencies have begun to alter their policies and regulations to relax agency control and give greater force to competition

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1/ *E.g.*, United States v. Philadelphia National Bank, 374 U.S. 321, 350-51 (1963); Silver v. New York Stock Exchange, 373 U.S. 341, 357-61 (1963).

as a factor in market control (ICC, FCC). It is important to realize that such regulatory opening of a regulated business to competition is not a shift to the free and open competition of economic theory such as may exist in agriculture and in neighborhood grocery stores. On the contrary, the shift from regulation to competition is more truly a shift to controlled or regulated competition. 1/ The Interstate Commerce Commission, after having indicated it would ease entry of new firms into the trucking business, has been swamped with applications for entry which it must approve or disapprove on the basis of regulatory standards such as safety, financial responsibility, etc. Similarly, the Federal Communications Commission in permitting competition in some aspects of the telecommunications business, has stated that it will judge the desirability of competition on the existing public interest basis. In other words, regulation in the public interest is not to be abandoned for the sake of competition, but will be modified by competitive considerations.

Nevertheless, the argument for implied immunity because of pervasive regulation necessarily weakens to the extent that regulation is diminished.

Changes in the regulation of individual regulated industries are not as much of a threat as the broad-brush approach of the Kennedy bill. If rigidly followed, that bill would turn the regulation of business in the United States topsy-turvy. It would be an almost insoluble paradox to require that in a situation where a state or federal

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1/ A recent example of this is a proposal by A. Kahn that pending legislation to restructure the telecommunications industry should be modified to require that AT&T form a new subsidiary to perform its non-regulated activities; that any technology or new equipment furnished by AT&T to its subsidiary must be furnished on the same basis to the competitors of the subsidiary, and that AT&T must not compete in the long lines business for several years in order to give new competitors a chance to become established. That would be regulation of competition, with a vengeance. For other examples, see Satellite Business Systems, 62 F.C.C.2d 997, 1070 (1977) aff'd sub nom. United States v. FCC, 1980-1 Trade Cas. (CCH) ¶ 63,264 (D.C. Cir. March 7, 1980). 60 F.C.C.2d 939 (1976); Bell System Tariff Offerings of Local Distribution Facilities for Use by Other Common Carriers, 46 F.C.C. 413, aff'd sub nom. Bell Telephone Co. v. FCC, 503 F.2d 1250 (3d Cir. 1974), cert. denied sub nom. AT&T v. FCC, 422 U.S. 1026 (1975); AT&T, Investigation into the Lawfulness Of Tariff F.C.C. No. 267, Offering a Dataphone Digital Service Between Five Cities, 62 F.C.C.2d 774 (1977).

legislature has decided that agency regulation will better serve the public interest than a market controlled by competition, Congress later stated that the promotion of competition must be a primary objective of the agency. The Kennedy bill, if it becomes law, will probably multiply antitrust attacks upon regulated businesses. Private attorneys and the Department of Justice and the FTC could be expected to bring antitrust actions against regulated businesses and to argue that the "Competition Improvement Act of 1979" is an expression by Congress of the paramount importance of competition in the regulation of business, and thus a congressional direction that competition in regulated businesses should be enforced by application of the antitrust laws.

ELEVENTH SESSION, Thursday, May 22

ANNUAL FINANCE PANEL: RATE OF RETURN - NEW CONCEPTS

CHAIRMAN: H. A. Latimer

SPEAKERS: Eugene F. Brigham
Graduate Professor of Finance
University of Florida

Robert H. Litzenberger
C.O.G. Miller Distinguished Professor of Finance
Stanford University

THE RISK PREMIUM APPROACH TO

ESTIMATING THE COST OF COMMON EQUITY CAPITAL

Eugene F. Brigham and Dilip K. Shome
University of Florida

One of the basic approaches to estimating the cost of common equity capital is the risk premium method, sometimes called the stock-bond yield spread method. Because investors are risk averters, the required rate of return increases as the riskiness of a financial asset increases. Therefore, if investors have the opportunity to buy default-free U.S. Treasury bonds with a yield of 8 1/2 percent, they would require higher rates of return on corporate bonds and still higher returns on common stocks.[1] The question is, how much higher? If we knew the answer to this question, we could, at any given time, determine the cost of common equity simply by adding the risk premium to the current yield on Treasury bonds.

The basic idea behind the risk premium approach is indicated in Figure 1. The horizontal axis reflects risk--the further to the right a particular security lies, the greater its investment risk. Since U.S. Treasury bonds are free of default risk, they are shown at the origin. The vertical axis gives required rates of return, while the lines labeled SML_{1965} and SML_{1979} are "security market lines" which show, at two points in time, the assumed relationship between a security's risk and its required rate of return.

The term R_F designates the risk-free rate, or the rate of interest on U.S. Treasury bonds. It consists of a "real" or inflation-free rate (RR) plus a premium for expected inflation:

$$R_F = RR + \text{Inflation premium}.$$

In 1965 the riskless rate, $R_{F\ 65}$ in Figure 1, was about 4 percent. In 1979 the expected long term inflation rate was considerably higher, which resulted in a 10.0 percent rate on long-term governments.

Corporate bonds are riskier than U.S. government bonds, so their yields are higher. Recently, high grade utility bonds have commanded a premium of about one percentage point more than governments, and risk premiums rise for lower-rated corporate bonds. (See Appendix A.) Therefore, if corporate bonds were shown in Figure 1, both their risk and their return would exceed that of U.S. Treasury bonds. Common

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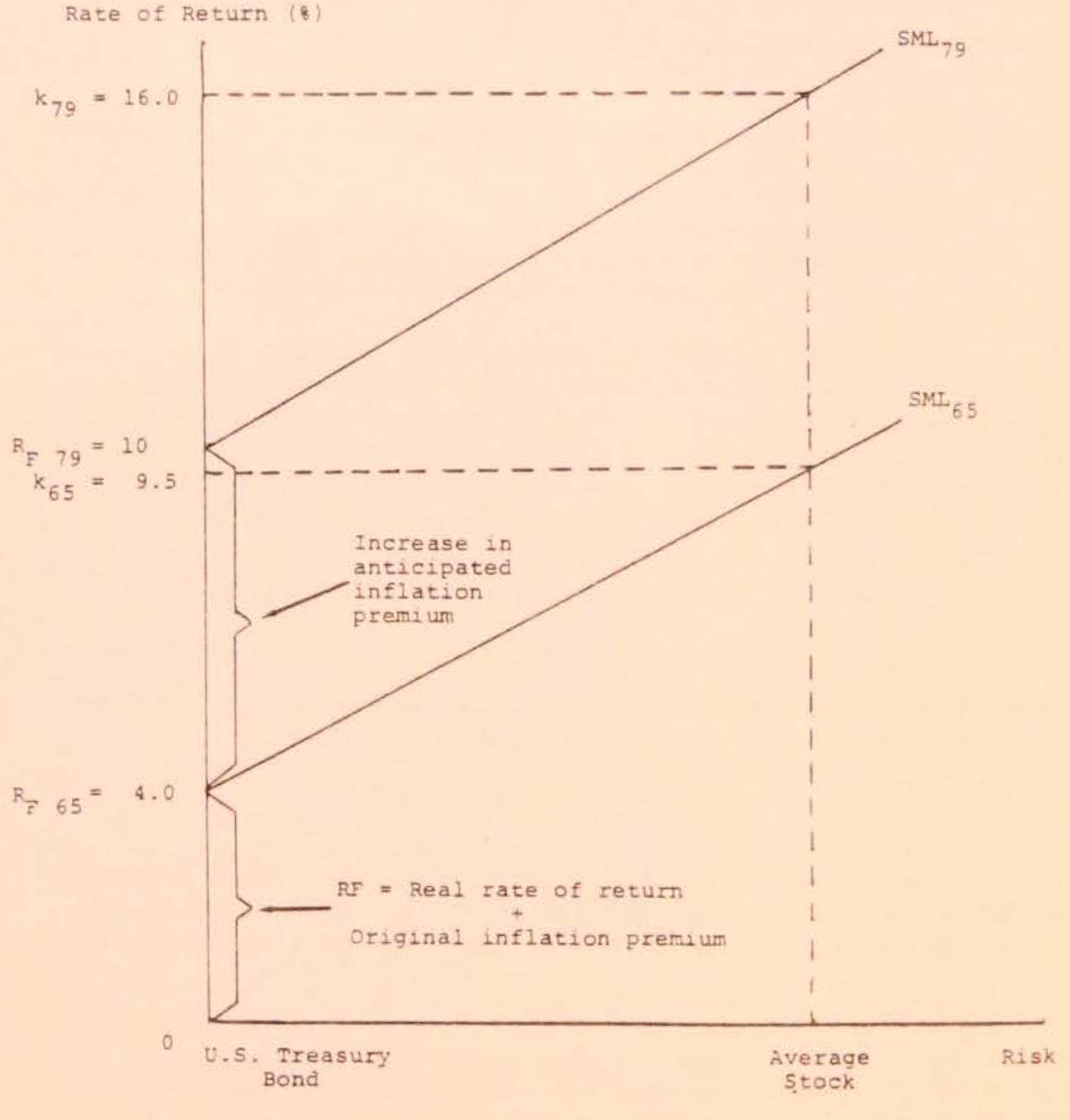
[1]U.S. Treasury bonds are riskless in the sense that they are free of default risk. However, they are not completely riskless because their holders still face the dangers of purchasing power loss (inflation risk) and the loss of capital values if interest rates rise (interest rate risk). The risk premiums which we develop could, therefore, be called default risk premiums.

Figure 1

RELATIONSHIPS BETWEEN INFLATION,
RISK AND REQUIRED RATES OF RETURN



stocks are, of course, much riskier than bonds, so their risk premiums are also much higher. In the graph we show an increase in the risk premium on an average share of common stock from 5.5 percent in 1965 to about 6.0 percent in 1979. Thus, when the yield on government bonds was about 4 percent, as it was in 1965, the required rate of return on an average share of common stock is shown to be about 9.5 percent. In 1979, when inflation had pushed the riskless rate up to 10.0 percent, the required rate of return on an average share of stock is shown to be about 16.0 percent.

Although the concept of risk premiums is widely accepted, there is no general consensus regarding (1) how to measure these premiums, (2) their general level, (3) changes in risk premiums over time, (4) the relative size of risk premiums on utility and industrial stocks, and (5) the risk premium on a specific firm's stock. Our purpose in this paper is to provide some answers to these questions.

ALTERNATIVE METHODS OF ESTIMATING RISK PREMIUMS

Three basic procedures have been used in attempts to estimate risk premiums: (1) historical studies of the returns actually earned on stocks and bonds, (2) surveys of institutional portfolio managers, and (3) premiums obtained by subtracting the expected yield on Treasury bonds from the average expected return on a group of "representative" common stocks. We subscribe to the third procedure, but it is nevertheless useful to consider the first two approaches as a point of departure for our work.

Historical Returns

There have been a number of historical studies of the actual rates of return on stock and bond portfolios over various past holding periods. In these studies, it is assumed that a portfolio of stocks is formed, held for a period of time, and then liquidated. Similarly, a bond portfolio is formed, and its historical rate of return is estimated. The difference between returns on the stock and bond portfolios is then determined, and this historical yield spread is then used as an estimate of the risk premium of stocks over bonds.

There are some serious problems with this procedure. One is the choice of holding period: The particular holding period used is essentially arbitrary, but it can make a huge difference in the final outcome. If short holding periods are used, returns will be especially volatile, but even assuming holding periods of ten years or more, realized rates of return, and consequently "risk premiums," can vary by as much as 20 percentage points.[1] Even with holding periods in the twenty to fifty year range, the calculated rate of return on common stocks (before personal taxes) in the period 1926-1978 ranged from 3.1% to 16.9%. Returns on long-term U.S. Government bonds ranged from 0.9% to 4.5% (capital losses on bonds held down their realized returns) over the same period. Therefore, risk premiums on an average share of stock as determined by historic data ranged from -0.8% to 15.0% even using these holding periods as long as twenty years. If shorter periods were used, much wider ranges of risk premiums could be obtained. Also, choosing as an ending point a year when the stock market closed very strong (such as 1968) or very weak (such as 1974) would have a tremendous effect on the calculated risk premiums. If one simply uses the most recent available year in an attempt to avoid arbitrariness, the historical record would still reveal major swings from year to year.

An even more important weakness in the use of historic yield spreads as estimates of current risk premiums is the fact that the true risk premium built into the cost of common equity at any point in time reflects the difference between expected returns on stocks and bonds in the future. Expected, or ex ante returns may, on rare occasions, equal the actual ex post returns that were realized in some past period, but this would be the exception, not the rule. For example, the consensus view of investors may be that if they buy a

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[1] R.G. Ibbotson and R.A. Sinquefield, Stocks, Bonds, Bills, and Inflation: Historical Returns (1926-1978) (Charlottesville: Financial Analysts Research Foundation, 1979).

portfolio of common stocks on January 1, 1980, and hold them until December 31, 1985, they will earn a before-tax rate of return (dividends plus capital gains) of 15 percent. This is the ex ante expected return. However, on December 31, 1985, if one looks back and determines the actual ex post realized rate of return from January 1, 1980, to December 31, 1985, it will almost certainly be higher or lower than the 15 percent expected return. The actual realized return might even be less than the realized return on bonds. If so, this would indicate a negative risk premium, which is clearly nonsense.

Because of these problems, risk premiums based on historic yield spreads are questionable. For purposes of estimating the cost of capital, it is more logical to base risk premiums on forward-looking than on backward-looking data.[1]

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[1] In rate cases, witnesses sometimes compare realized returns on book equity (ROE) to yields to maturity on bonds (YTM), calling the difference a risk premium. This procedure mixes historic returns (ROE) with forward-looking returns (YTM), and the result is not likely to be a meaningful figure. Only if (1) the expected future ROE is the same as the past ROE and (2) the stock is selling at its exact book value would this procedure give an accurate estimate of the cost of equity.

SURVEYS OF PORTFOLIO MANAGERS

Since institutional investors (primarily pension fund managers) make approximately 70 percent of the buy and sell decisions in the stock market, and an even larger percentage of bond transaction decisions, they largely control relative stock and bond prices and yields. Therefore, a second approach to the development of risk premiums is to survey institutional portfolio managers. To see how this approach is applied, one must understand how the portfolio managers of large institutional investors generally operate when they decide to invest or not to invest in a given stock:

1. A DCF rate of return (dividend yield plus capital gains yield) is estimated for each stock under consideration. This gives an expected rate of return for each stock. To illustrate, a bank trust department portfolio manager might obtain from the bank's security analysts a projection that American Telephone's dividends, which were $5.00 during 1979, will grow at a rate in the range of 5 to 6 percent per year for the next five years, and that the price of the stock will also grow at this same rate. If the stock is purchased at a price of $52 per share, held for five years, and then sold, it will have provided an annual market value rate of return in the range of 15.1 to 16.2 percent.

2. Obviously, common stocks are not riskless. For example, AT&T's stock price declined from a high of about $75 in the mid-1960's to about $39 in 1974, and from $64 3/4 to $45 during the 1979-80 decline. Because different stocks are regarded as facing different amounts of risk exposure, institutional investors find it useful to group each stock into one of several "risk classes." Five risk classes are often used. Group 1 might be composed of the 20% of the stocks judged least risky, Group 2 would consist of the next least risky stocks, and so on. These risk groupings are based partly on quantitative data, but the actual placements are largely judgemental.

3. The next step is to establish a required rate of return for each stock. This could be done by adding a premium to the U.S. Treasury bond rate or to a corporate bond rate such as the Aa rate. For the S&P 400 stocks, these premiums appear typically to be established at rates close to the following:

	Risk Premiums	
Stock Risk Group	Over U.S. Treasury Bonds	Over Aa Corporate Bonds
1. Lowest risk	4.5-5.0%	3.5-4.0%
2. 2nd lowest risk	5.0-5.5	4.0-4.5
3. Average	5.5-6.0	4.5-5.0
4. 2nd highest risk	6.0-6.5	5.0-5.5
5. Highest risk	6.5-9.0	5.5-8.0

These premiums are based partly on what investors think is reasonable, given their perceptions of current conditions and their aversion to risk, and this, in turn, may be influenced by historic risk/return relationships.

4. The expected and required returns are next compared. If expected returns on stocks exceed required returns, investors tend to buy equities rather than debt, and vice versa. Any company or industry whose expected return exceeds its required return by a relatively large amount is favored, and conversely. When the consensus view of investors is that the expected returns on most stocks are above or below their required returns, the collective actions of investors will cause stock prices to rise or fall. Such price changes, in turn, will restore equilibrium to the market, with expected returns equal to required returns.

A study was recently conducted by Charles Benore of Paine Webber Mitchell Hutchins, Inc., a leading institution-oriented investment banking concern, in an attempt to quantify the ideas in the preceding paragraphs.[1] A summary of Benore's study is given in Table 1. Eighty-five percent of the portfolio managers surveyed assigned a risk premium of from 4 to 6 percentage points, with an average of 4.90 percentage points, to utility stocks over Aa bonds. Since Aa bonds typically yield about one percentage point more than long-term government bonds, this suggests a premium over governments of about 6 percentage points for Aa electrics. Of course, the Mitchell Hutchins study is restricted to the high quality electrics, but it is nevertheless suggestive of the risk premiums for stocks in general.[2]

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[1] Charles Benore, Paine Webber Mitchell Hutchins, Inc., "A Survey of Investor Attitudes toward the Electric Power Industry," September 25, 1979.

[2] Some analysts have suggested to us that the risk premium on a utility stock over its own bonds may be wider than that for industrial stocks because of regulators' treatment of debt versus equity. Regulators may be willing to hold a utility's equity returns down to a level that causes severe stock price losses even when economic (as opposed to political) conditions would permit a rate increase, but it is hard to imagine rates being held down to a level that causes the company's bonds to go into default.

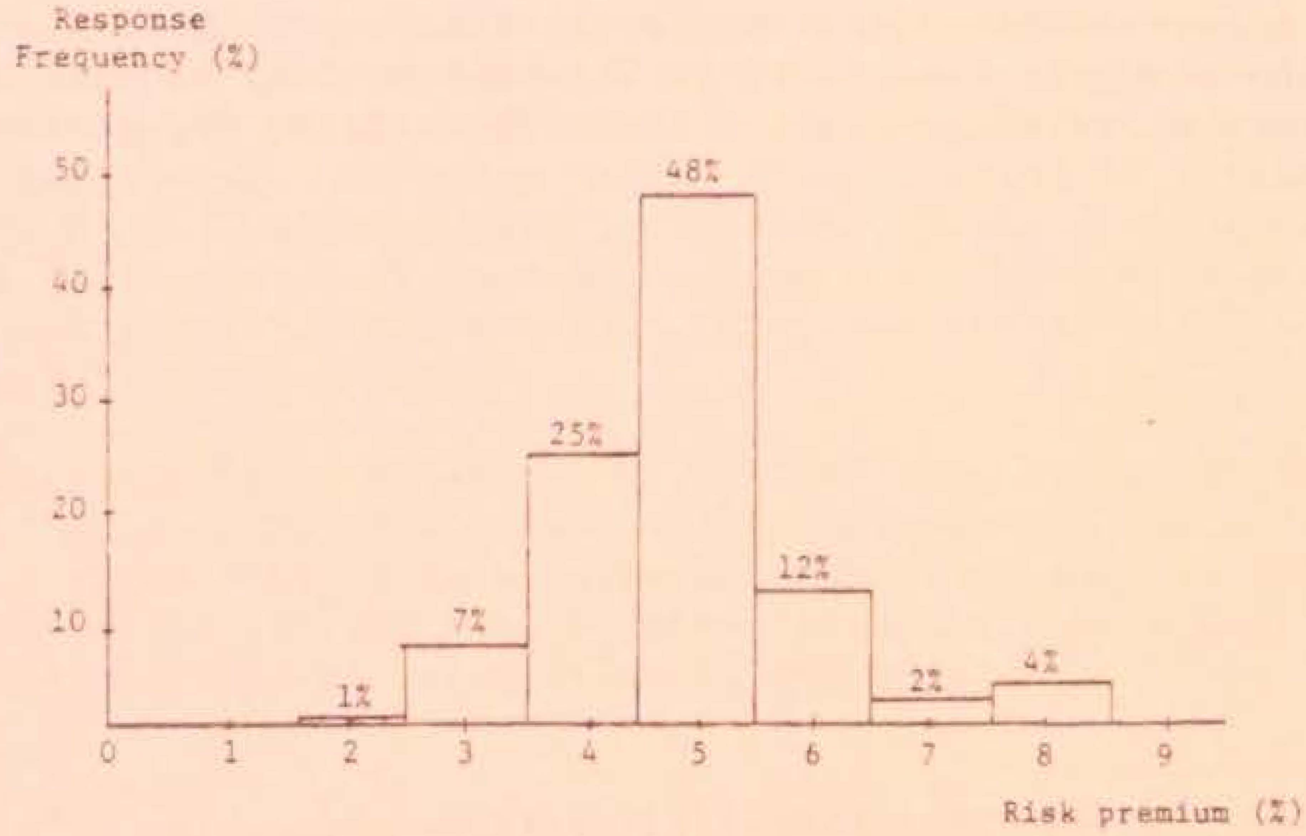
Table 1. Summary of Benore's Risk Premium Study

I. Question put to portfolio managers:

Assuming that a double A, long-term utility bond currently yields about 9 1/2%, the common stock for the same company would be attractive to you relative to the bond if its expected total return was at least:

Total Return	Indicated Risk Premium (basis points)
over 19%	over 900
18 - 19	900
17 - 18	800
16 - 17	700
15 - 16	600
14 - 15	500
13 - 14	400
12 - 13	300
11 - 12	200
under 11	under 200

II. Distribution of Responses



Weighted average (expected value) risk premium = 4.9%

Source: Paine Webber Mitchell Hutchins, Inc., "A Survey of Investor Attitudes toward the Electric Power Industry," September 25, 1979.

DCF MODEL RISK PREMIUMS

The survey approach is conceptually superior to the historical returns approach in that it attempts to estimate risk premiums based on expected future returns rather than past realized returns. However, there is a possibility that survey data may be biased or otherwise unreliable. Therefore, as an alternative to asking investors for the risk premiums they use, we have reversed the process and inferred from the stock prices and bond yields that exist in the market the risk premiums that investors apply.

Different organizations (institutional investors, brokerage house analysts, and advisory services) use different data bases and methodologies for valuing stocks, and each analyst tries to do something unique to get an edge on the other 50,000 or so professional analysts who are seeking to forecast stock prices and to pick the best buys from among the thousands of available stocks. However, discussions with analysts and portfolio managers, a review of investments textbooks and such professional journals as The Institutional Investor and The Analysts' Journal, and a study of materials prepared by the Financial Analysts' Federation and the Institute of Chartered Financial Analysts suggest that we can form a reasonably accurate estimate of the consensus expected rate of return by use of the DCF model.

Depending on what assumptions are made about the long-term dividend growth of a firm, the DCF model is typically used in either of the following forms:

1. Constant Growth, or Gordon model.

2. Non-constant growth DCF model.

With the constant growth model, we estimate the expected return on equity (k) as follows:

$$k = D_1/P_0 + g. \qquad (1)$$

Here D_1 represents the dividends expected during the next twelve months, P_0 is the current price of the stock, and g is the long-run expected growth rate in dividends. The major assumption of this model is that dividends will grow indefinitely at a constant rate g.

In the non-constant growth DCF model, we allow for the possibility that investors could, for various reasons, expect a firm's growth rate to vary over time. In our analysis, we assume that dividends grow in an irregular manner for N years, after which it will experience a stable, normal growth rate, g_n. Under these assumptions, we can write the DCF equation as follows:

$$P_0 = \sum_{t=1}^{N} \frac{D_t}{(1+k)^t} + \left(\frac{D_N(1+g_n)}{k-g_n}\right)\left(\frac{1}{1+k}\right)^N. \qquad (2)$$

The last term in the equation utilizes the constant growth model to find the present value of all future dividends beyond Year N. Knowing the values of all other variables, we can solve this equation to determine k.

Using either the constant or non-constant model, if we develop an expected return for the market index (k_M) and then subtract from this return the yield on a risk-free security (R_F), we will have estimated a forward-looking risk premium for the market (RP_M):

$$RP_M = k_M - R_F. \qquad (3)$$

The accuracy of this method depends on the proper measurement of the riskless rate and on the validity of the assumptions of the DCF model used to determine k_M. These topics are discussed next.

THE RISKLESS RATE

For reasons we have pointed out elsewhere,[1] the best choice of a riskless rate for purposes of calculating equity risk premiums is the "constant maturity" long-term U.S. Treasury bond rate series which abstracts from the effect of "flower bonds." The use of such short-term interest rates as T-Bills will almost certainly produce misleading and unstable results because (1) the expected rate of inflation is not constant over time and (2) through the expectations theory mechanism, long-term and short-term securities embody different average expected future interest rates. Thus, increases or decreases in the T-Bill rate reflect increases and decreases in near-term inflation rates, while increases or decreases in long-term bond rates reflect changes in expected long-term inflation rates. Since expectations about short-term inflation rates are <u>far</u> more volatile than expectations about long-term inflation, short-term rates are more volatile than long-term rates. Further, since stocks are long-term securities, they are more like bonds than bills with respect to inflation-induced movements. Therefore, stock returns are more highly correlated with movements in long-term bond rates than short-term rates, which makes it more appropriate to base equity risk premiums on long-term than on short-term Treasury security rates.[2]

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[1] E.F. Brigham and D.K. Shome, "The Riskless Rate of Return in Risk Premium Studies," Public Utility Research Center Working Paper, May 1980.

[2] To some extent, utility stocks are increasingly coming to resemble a sort of low grade, floating rate income bond rather than a long-term bond. Because of inflation, utilities must go in for frequent rate cases, and the returns on equity (ROE) allowed in each rate case are dependent in part on current capital market conditions. If interest rates move up and down, then so will allowed ROE's. Coupons on outstanding bonds, on the other hand, are fixed for the life of the bond. Thus, in a sense, bonds have longer effective lives than utility stocks. This suggests that it might be more appropriate to compare utility stocks with intermediate term Treasury securities. We are currently studying this issue.

THE CONSTANT GROWTH MODEL

To apply the Gordon Equation to a group of stocks taken to represent "the market," we estimate the average or "market" required rate of return, k_M, as follows:

$$k_M = (\text{Dividend yield})_M + (\text{Growth rate in dividends})_M.$$

Here

$$(\text{Dividend yield})_M = \frac{\text{Total dividends expected to be paid on all stocks in next period}}{\text{Total current market value of all stocks}},$$

and

$$\begin{pmatrix}\text{Growth rate}\\ \text{in dividends}\end{pmatrix}_M = \begin{pmatrix}\text{Constant long-term rate}\\ \text{at which dividends are}\\ \text{expected to grow}\end{pmatrix}.$$

There are two major problems with this procedure. First, the constant growth model applies only to individual companies whose expected future growth rates are relatively constant; that is, the estimated growth rate for any year t is equal to the rate expected in Year t + 1. This means that it is most applicable to the larger, more mature companies, while it is not applicable (without a major reformulation) at all to smaller, rapidly developing companies. Therefore, if the market portfolio does not consist of constant growth companies, then the aggregated data will not meet the model's required conditions. Second, even if the expected growth rate is constant over time, estimating it is a very difficult task.

While these problems certainly exist, they are not insurmountable, and security analysts deal with them on a daily basis. Further, it may be reasonable to assume that errors associated with estimates of individual companies will, to a large extent, cancel one another out when we average across a large sample of companies to develop the risk premium on the market portfolio.[1] Also, the problem of nonconstant growth can be reduced if not eliminated by restricting our analysis to the larger, more mature companies. Accordingly, we chose two market indices for our analysis: (1) the S&P 400 Industrials and (2) the Dow Jones 30 Industrials.[2] Most of the companies in these

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[1]The situation here is similar to that encountered in portfolio analysis. Betas of individual securities tend to be unstable and to reflect a great deal of measurement error. However, when companies are grouped into portfolios, the portfolio betas tend to be highly stable. The same type of situation may also exist here.

[2]We eliminated AT&T from both our samples since AT&T is a regulated utility and should not be treated as an unregulated industrial. Our indices are therefore the "S&P 399" and the "Dow Jones 29." We will examine AT&T and the other utilities separately.

indices have been in business for many years, are well established in their lines of business, and have sales and profits which tend to move with the level of general economic activity. While none of the companies can be expected to grow at an identical rate from year to year, it is still true that for most of them the expected long-run future growth rate is constant in the sense that the best estimate of the growth rate for, say, 1985 is the same as the best estimate for 1984 or 1986.

Of course, limiting our analysis to larger companies means that we cannot draw from the study any inferences about risk premiums and the cost of capital for smaller companies. On the other hand, limiting the analysis does permit us to make better estimates of these values for larger firms.

Estimating Growth Rates

The most difficult problem in implementing the DCF model is to obtain a good estimate of the expected future growth rate. If a company has experienced a relatively steady, stable growth in earnings and dividends, and if this past rate of growth is expected to continue into the future, then past growth rates might be extrapolated and used to project future growth. However, because of inflation and other factors, the steady growth situation has not held for most companies in recent years, so analysts have developed other methods of making growth forecasts. One well-recognized and widely used procedure involves multiplying the fraction of a company's earnings which investors expect it to retain (b) by the expected rate of return on book equity (ROE):

$$g = b(ROE).$$

This procedure matches investors' estimates of future growth if, and only if, the following conditions hold:

1. The percentage of earnings retained is expected to remain constant over time. Investors never literally expect a constant retention rate, but the assumption is satisfied if the best current estimate of the retention rate during any future year is the same as the expected rate for any other future year.

2. Investors expect the company to sell no new common stock, or to sell it, on average, at about book value.

3. The future rate of return on book common equity is expected to fluctuate randomly around some constant level over time, making the best guess as to the ROE for any future year, say 1984, the same as that for any other year, say 1985.

If these three conditions are expected to hold true into the indefinite future, then a precise estimate of the future growth rate can be obtained with the equation $g = b(ROE)$. If these conditions are not met exactly, then the equation will not produce an exactly accurate growth estimate. Since the three conditions have not held exactly in the past and will not hold exactly in the future, the formula has limitations. However, the formula does give a reasonably accurate estimate of long-term growth for large companies, and it is, in any event, far more accurate than simply assuming that past growth rates will be maintained.

To estimate g_M, the expected market growth rate, we need estimates of b_M and ROE_M. Most companies have target payout ratios that are reasonably stable over time, so their target retention rates (b) are also reasonably stable. Earnings vary from year to year, so the actual (as opposed to the target) payout and retention rates will vary, but these variations will be around the target values. Therefore, to estimate the target retention rate (which is the value we need for the growth rate formula) we may take an average of retention rates in the recent past. The period used to develop the average should be long enough to cover both peaks and troughs of business cycles, but not so long as to include data that is "ancient history" and which no longer reflects the firm's operating conditions.

There is no one correct method for developing expected future growth rates from past data. Different investors surely process and interpret the existing data differently and, thus, reach different conclusions as to the best estimate of a firm's future growth.[1] Therefore, depending on our assumptions as to how most investors derive growth estimates, we can obtain different projected growth rates, hence different estimates of expected market returns and risk premiums. We experimented with several different procedures for estimating growth rates. For the aggregated set of companies, differences in the risk premiums derived by the different methods were generally rather small, with the average risk premiums from 1964 to 1979 ranging from 5 to 7 percent.

The results reported in this paper utilize estimates of the expected growth rate based on weighted average data, giving the most weight to the most recent data. To derive the estimate of g using the formula g = b(ROE), we estimated the value as of Year t for the expected retention rate (b) during Year t + 1 and future years as follows:[2]

$$(b_M)_{t+1} = 0.4(b_M)_t + 0.3(b_M)_{t-1} + 0.2(b_M)_{t-2} + 0.1(b_M)_{t-3}.$$

Here

$$(b_M) = 1.0 - \frac{\text{All common dividends paid by all S\&P 399 firms}}{\text{Total earnings available to common stockholders}}$$

$$= 1.0 - \frac{(DIV_M)}{(Earnings_M)} .$$

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[1] Indeed, as L.D. Brown and M.S. Rozeff ("The Superiority of Analyst Forecasts as Measures of Expectations: Evidence from Earnings," Journal of Finance, March 1978) have shown, analysts use subjective information that would be difficult if not impossible to extract from historic data.

[2] We describe here the estimating procedure for the S&P 399. The identical methodology is also used for the Dow Jones 29.

The expected rate of return on common equity (ROE) was calculated similarly:

$$(ROE_M)_{t+1} = 0.4(ROE_M)_t + 0.3(ROE_M)_{t-1} + 0.2(ROE_M)_{t-2} + 0.1(ROE_M)_{t-3}.$$

Here, ROE_M is the market value weighted average return on book equity,[1]

$$ROE_M = \left[\sum_{i=1}^{399} (MVF_i)(ROE_i)\right] ,$$

and MVF_i is the market value fraction of each company i, (Market value of Firm i)/(Total market value), while ROE_i is the return on average common equity for the i$^{\underline{th}}$ company.

Given these estimates of the market retention rate and the market ROE, we obtain an estimate of the expected future market growth rate as follows:

$$(g_M)_{t+1} = (b_M)_{t+1} \times (ROE_M)_{t+1} .$$

This is the g value used in the DCF equation.

Estimating Dividend Yields

Once we have estimated the expected growth rate, the next element needed to implement the constant growth Gordon model is the expected dividend yield on the market, which for the S&P 399 is calculated as follows:

$$\begin{pmatrix}\text{Expected Market}\\ \text{Dividend Yield}\end{pmatrix}_{t+1} = \frac{(\text{Total dividend on S\&P 399})_t (1 + g_M)_{t+1}}{(\text{Total market value of S\&P 399})_t}$$

$$= \frac{(D_M)_t (1 + g_M)_{t+1}}{MV_t} .$$

[1]One could develop aggregate data on the basis of either book value or market value weights. Market value weights are more consistent both with financial theory and also with the fact that industrial companies with higher market/book ratios are growing faster and, hence, making larger incremental investments than firms with low M/B ratios.

We should also note that the choice of a four year period, and the 0.4, 0.3, 0.2, and 0.1 weights, is arbitrary, but that we did sensitivity tests using longer and shorter periods, and with weights set by exponential smoothing techniques. The results were not materially influenced by the use of exponential smoothing, and the choice of periods did not matter within the range of 3 to 6 years.

We based the market value on December 31st closing prices. We considered using various types of average stock prices, but we ultimately concentrated on spot prices because they are conceptually better. Since the stock market is relatively efficient, especially for large companies such as those in the S&P Industrial Index, the year-end closing price should reflect all currently available information on that date, and any average prices based on earlier data would probably be misleading in the sense that earlier prices would not reflect information and market conditions as of December 31. Of course, using a spot price does mean that this price can reflect some random movement away from the equilibrium price, but (1) in an efficient market such random fluctuations are not likely to be large, and (2) the net effect of random fluctuations should be small in a sample as large as the S&P Industrials.[1]

The Market Risk Premium

Having determined the expected growth rate and dividend yield on the market, we can sum these two components to obtain the expected rate of return on the market:

$$(k_M)_{t+1} = \frac{(D_M)_t \ (1 + g_M)_{t+1}}{(MV)_t} + (g_M)_{t+1}.$$

Subtracting the yield to maturity on U.S. Treasury bonds (R_F) from k_M produces an estimate of the risk premium investors require on the market:

$$RP_M = k_M - R_F.$$

Here R_F is the December yield for the 20-year Constant Maturity Series.

In effect, we have estimated market returns looking forward from January 1 of a particular year. The bond yields used are returns that will be earned (with certainty) if the bonds are purchased and held to their 20-year maturity. The difference between the expected stock return and the bond yield is an estimate of the risk premium on the S&P or Dow Jones Industrial Stock Indexes.

Tables 2 and 3 show estimated risk premiums, plus certain other data, for the two industrial indexes, while Figures 2 and 3 give plots of the key values. The major points of interest, which can be seen most clearly from the graphs are these:

1. Risk premiums seem to vary from year to year. Some of this year-to-year variation probably reflects random errors in our estimating procedures, although some

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[1]We experimented a bit with stock prices, within the limits imposed by use of the Compustat Data Tapes. In addition to the closing price, we also used (1) the average of the January 1 and December 31 prices, and (2) the average of the high and the low for the year. On average, the choice of stock price definition did not materially affect the calculated risk premiums.

Table 2. Estimated Risk Premiums, Constant Growth, 1964-1979, for the S&P 399 Industrial Index

Beginning of Year	Expected Dividend Yield $(Y)_M$	Expected Growth Rate $(g)_M$	Expected DCF Return on Equity $(k = Y + g)_M$	20-Year Government Bond Yield (R_F)	Risk Premium $(RP = k - R_F)_M$	3-Year Centered Moving Average (RP)
1964	3.30%	6.19%	9.49%	4.19%	5.30%	-
1965	3.19	6.67	9.86	4.18	5.68	5.70%
1966	2.96	7.65	10.61	4.50	6.11	6.35
1967	3.61	8.41	12.02	4.76	7.26	6.37
1968	2.85	8.48	11.33	5.59	5.74	6.17
1969	2.83	8.56	11.39	5.88	5.51	5.30
1970	3.14	8.42	11.57	6.91	4.66	4.91
1971	3.13	7.70	10.83	6.28	4.55	4.57
1972	2.72	7.79	10.51	6.00	4.51	4.61
1973	2.38	8.34	10.72	5.96	4.76	4.93
1974	3.17	9.63	12.81	7.29	5.52	6.05
1975	5.00	10.78	15.78	7.91	7.87	6.49
1976	3.80	10.52	14.32	8.23	6.09	7.03
1977	3.71	10.71	14.42	7.30	7.12	6.95
1978	5.02	10.50	15.52	7.87	7.65	7.30
1979	5.32	10.72	16.03	8.91	7.12	-
Average	3.51%	8.82%	12.33%	6.36%	5.97%	

Table 3. Estimated Risk Premiums, Constant Growth, 1964-1979, for the Dow-Jones 29 Industrials

Beginning of Year	Expected Dividend Yield $(Y)_M$	Expected Growth Rate $(g)_M$	Expected DCF Return on Equity $(k = Y + g)_M$	20-Year Government Bond Yield (R_T)	Risk Premium $(RP = k - R_T)_M$	3-Year Centered Moving Average $(\overline{RP})$
1964	3.53%	5.24%	8.77%	4.19%	4.58%	-
1965	3.48	5.39	8.87	4.18	4.69	4.76%
1966	3.15	6.35	9.50	4.50	5.00	5.23
1967	3.83	6.92	10.75	4.76	5.99	5.20
1968	3.01	7.20	10.20	5.59	4.61	5.08
1969	3.18	7.33	10.51	5.88	4.63	4.26
1970	3.46	7.00	10.46	6.91	3.55	3.73
1971	3.29	5.99	9.28	6.28	3.00	3.30
1972	3.02	6.33	9.35	6.00	3.35	3.37
1973	2.75	6.96	9.72	5.96	3.76	4.01
1974	3.82	8.38	12.20	7.29	4.91	5.35
1975	5.94	9.35	15.29	7.91	7.38	5.67
1976	4.20	8.76	12.96	8.23	4.73	5.96
1977	4.34	8.73	13.07	7.30	5.77	5.60
1978	6.05	8.13	14.18	7.87	6.31	5.98
1979	6.14	8.63	14.77	8.91	5.86	-
Average	3.95%	7.29%	11.24%	6.36%	4.88%	

FIGURE 2.

ESTIMATED ANNUAL RISK PREMIUMS, S&P 399 INDUSTRIALS AND DOW JONES INDUSTRIALS, CONSTANT GROWTH MODEL (1964-1979)

Panel (a)

3-YEAR CENTERED MOVING AVERAGE RISK PREMIUMS, S&P 399 INDUSTRIALS AND DOW JONES INDUSTRIALS, CONSTANT GROWTH MODEL (1964-1979)

Panel (b)

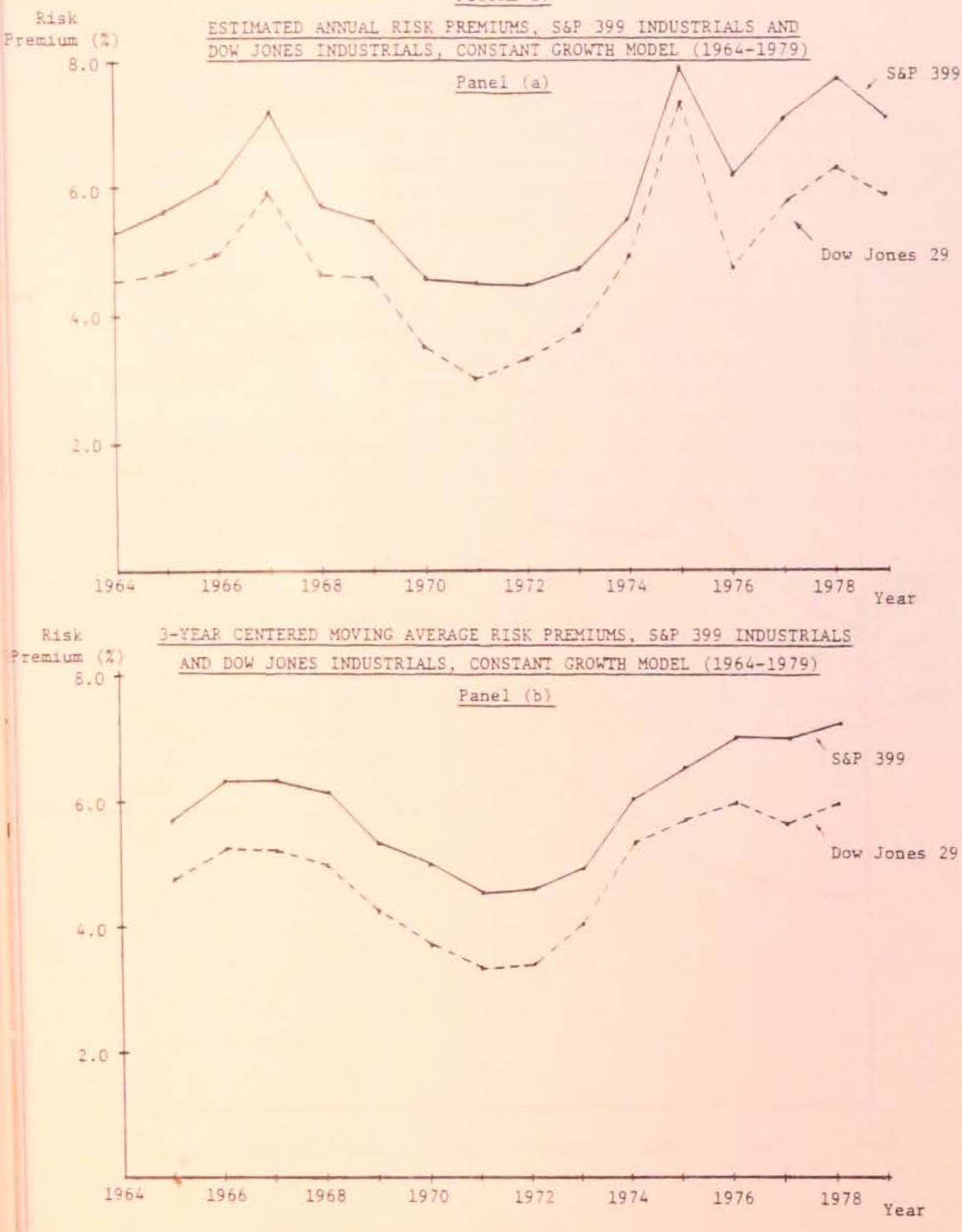
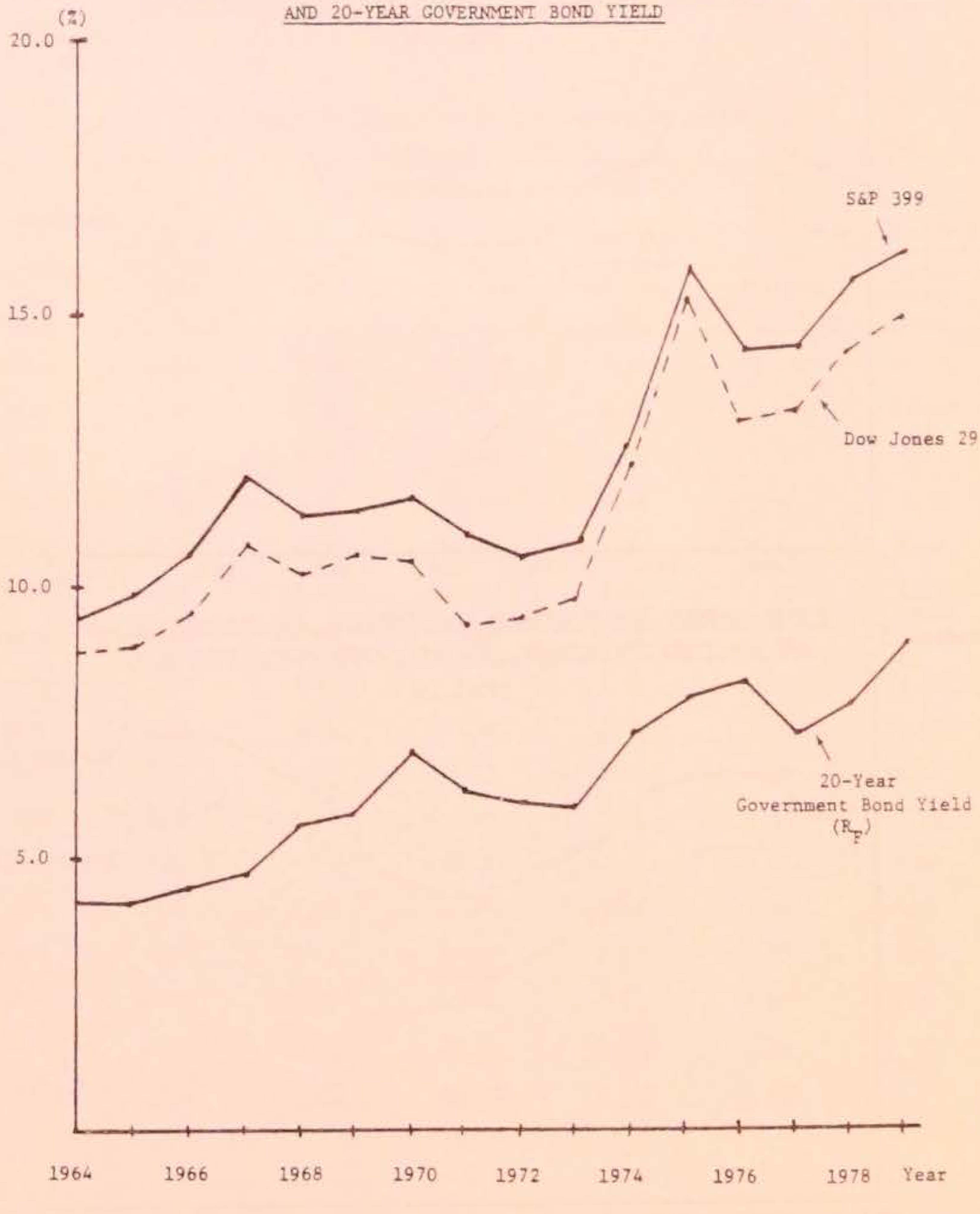


FIGURE 3: EXPECTED CONSTANT GROWTH DCF RETURN ON EQUITY AND 20-YEAR GOVERNMENT BOND YIELD



undoubtedly reflects changes in investors' outlooks and degree of risk aversion.

2. Two clear trends in risk premiums are evident in the graph--risk premiums drifted downward rather steadily from the mid-1960's until 1974, but they have climbed sharply in recent years.

3. Because some of the year-to-year variations are undoubtedly caused by random errors, the 3-year moving averages may be more reflective of the true market risk premiums than are the actual annual numbers. However, judgment on this point should be reserved until we have examined results produced by the nonconstant growth model.

4. The expected rate of return, and consequently the risk premium, for the S&P 399 and the Dow Jones 29 track one another very closely over time; in fact, the correlation between these two series is 0.97. However, both the expected rate of return and the risk premium are consistently higher for the S&P 399; on average, this differential is about one percentage point. The lower apparent risk for the Dow Jones stocks is probably attributable to the fact that they are larger, stronger companies than the broader S&P index.

5. There is a very strong correlation between equity returns and bond yields; this is evident from Figure 3. The correlation coefficient between the bond yields and returns on the S&P 399 index is 0.88, and that between bond yields and returns on the Dow Jones 29 is 0.86. We would expect equity returns to rise when debt returns increase, and it is obvious that they do.

THE NONCONSTANT GROWTH MODEL

The nonconstant growth model requires solving for k in Equation 2:

$$P_0 = \sum_{t=1}^{N} \frac{D_t}{(1 + k)^t} + \left(\frac{D_N(1 + g_n)}{k - g_n}\right)\left(\frac{1}{1 + k}\right)^N . \qquad (2)$$

Here, P_0 is the firm's current price; D_t is the expected dividend in Year t; N is the number of years before the constant growth state is reached; and g_n is the constant (or "normal") growth rate expected to prevail after N periods. Knowing the values of these variables, we can solve Equation 2 for k, the firm's expected and required rate of return.

The required input data for this model cannot be generated by a mechanical process--specific analysts' forecasts are necessary. We need estimates for a large number of companies, and the most convenient source of such forecasts--indeed, the only source of historical forecasts we have discovered--are those published by Value Line in its Investment Survey. However, unlike operations with the Compustat tapes, it is a difficult (and expensive) task to collect data from the old issues of Value Line. Therefore, we did not develop risk premiums with the nonconstant model for the S&P 399--rather, we restricted our analysis of industrial companies to the Dow Jones 29. However, we did collect data on and analyze the Dow Jones Electrics (the 11 electric utility stocks included in the Dow Jones Utility Index).

The derived risk premiums are valid estimates of the true market risk premiums only if (1) stocks are in equilibrium, with expected returns being equal to required returns, and (2) Value Line's analysts' expectations represent the consensus view of the market. The first condition is quite reasonable, but the second definitely poses a problem which will be discussed in more detail later in the paper.[1]

---

[1]Value Line's analysts seem to follow standard estimating techniques, and the Investment Survey is subscribed to by more individual and institutional investors than any other service. Second, the Value Line earnings and dividend estimates are reasonably consistent with forecasts of other analysts that we have examined. Third, all analysts, including Value Line's, use essentially the same data base for making forecasts, and they all generally confer with company officials to learn of new developments and to check on the reasonableness of their forecasts. For these reasons, at any point in time different security analysts typically make relatively consistent earnings and dividend forecasts for a given company, and especially for such large, stable, and widely followed companies as those we have examined. We also note that Value Line's forecasts have been studied in depth by academic researchers, and the Value Line quarterly earnings growth projections in the past have been superior to time series forecasts. However, Value Line's five year forecasts may or may not be accurate in comparison to other analysts' forecasts, and they may or may not represent the consensus view of investors. See L.D. Brown and M.S. Rozeff, "The Superiority of Analyst Forecasts as Measures of Expectations: Evidence from Earnings," Journal of Finance, March 1978, pp. 1-16.

Methodology

Value Line provides data which can be used to evaluate Equation 2 over a four year time horizon, so the nonconstant model is specified as follows:

$$P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \frac{D_4}{(1+k)^4} + \left(\frac{D_4(1+g_n)}{k - g_n}\right)\left(\frac{1}{1+k}\right)^4. \quad (3)$$

Value Line provides specific forecasts for D_1 and D_4; we obtained estimates of D_2 and D_3 by interpolation. Value Line also provides the data required to derive an estimate of g_n, the constant growth rate after Year 4. We estimate g_n as

$$g_n = b_n(ROE_n).$$

The value for b_n is the retention rate estimated by Value Line in Year 4,

$$b_n = 1 - D_4/EPS_4.$$

ROE is estimated as follows:[1]

$$ROE_n = ROE_4 = EPS_4/\text{Average Book Value}_4.$$

The estimates of b_4 and ROE_4 are combined to form an estimate of the growth rate in Year 4, which is assumed to be the expected long-run normal growth rate, g_n.[2]

---

[1]Value Line reports an ROE for the utilities but not for the industrial companies. For both groups, it does report the estimated tangible book value per share for t = 1 and t = 4. We interpolate to find book value at t = 3, then calculate the average book value as the average of t = 3 and t = 4.

[2]In a study similar to ours, B.G. Malkiel ("The Capital Formation Problem in the United States," Journal of Finance, May 1979, pp. 291-306) assumed a constant growth rate for the first five years, after which the growth rate was assumed to decay exponentially over the next fifteen years to a terminal growth rate equal to the estimated real growth rate in GNP (3-4%). This seems to us to be an unrealistically low forecast in an economy where inflation has averaged about 8% over the last decade. The earnings and dividends of a firm are expected to grow at the nominal rather than the real rate. However, Malkiel states that his results are insensitive to the terminal growth rate, the period of decay, and the rate of decay.

Sample Calculation of k_i for an Illustrative Firm

We show below the calculations for Southern Company, using Value Line data from the April 4, 1980, issue.

1. Value Line gives estimates of earnings and dividends for 1979, 1980, and averages of 1982-1984, which may be interpreted as estimates for 1983. Interpolating for 1981 and 1982, we obtain these estimates of earnings per share (EPS) and dividends per share (DPS):

	1979	1980	1981	1982	1983	Growth rate 1979-1983
EPS	1.51	1.70	1.90	2.10	2.30	11.09%
DPS	1.54	1.56	1.57	1.59	1.60	0.96%

Notice that earnings are projected to grow at an average rate of 11.09 percent versus a growth rate of less than one percent for dividends. Very clearly, the conditions necessary for the constant growth model do not hold, demonstrating the need for the nonconstant model.

2. Value Line also forecasts EPS for 1983 of $2.30 and an average book value in 1983 of $17.24, so the estimated 1983 ROE is 13.3 percent.[1] This ROE, combined with the 1983 retention rate of 0.3 or 30 percent, produces an estimated long-run growth rate of 4 percent:

$$g = b(\text{ROE}) = 0.3(13.3) = 3.99\% \approx 4\%.$$

This 4 percent is a forecast of the growth rate in earnings and dividends beyond 1983, and it is assumed to be a constant. We can insert the projected dividends and growth rate into Equation 2, along with the current market price of $12, and then solve for k to estimate the DCF cost of equity:

$$\$12.50 = \frac{1.56}{(1+k)^1} + \frac{1.57}{(1+k)^2} + \frac{1.59}{(1+k)^3} + \frac{1.60}{(1+k)^4} + \left(\frac{1.60(1.04)}{(k-0.04)}\right)\left(\frac{1}{(1+k)}\right)^4.$$

The solution value of this equation is k = 15.5 percent, and it is an estimate of Southern's cost of common equity capital. This same procedure was followed for each company in each sample (the 29 Dow Jones Industrials and the 11 Dow Jones Utilities) in each year from 1966 to 1979.

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[1] For the utilities, Value Line gives an estimated ROE in 1983; for Southern, this value is 13 percent. The difference, 30 basis points, results from two factors: (1) the use of tangible book value versus total common equity for the reported ROE and (2) the fact that the reported ROE is based on year-end rather than average common equity.

Analysis of Results

Proceding as described above, we estimated the risk premiums for the Dow Jones Industrials and the Dow Jones Electrics for the years 1966-1980. Table 4 and Figures 4 and 5 present our findings, which are summarized below:

1. It is apparent from Figure 4 that the cost of equity tracks interest rates quite closely; indeed, Treasury bond yields are correlated with industrial k values at the level r = 0.91, while for the electrics r = 0.92.

2. Figure 4 also shows that the cost of equity capital for the electric utilities has risen faster than that of the industrials--in the 1960's, when utilities were regarded as being safe, "widow-and-orphan" stocks, their cost of capital was much below that of the industrials. More recently, after the utilities have suffered huge market price declines as a result of regulatory lag, escalating fuel costs, environmental problems and the like, their cost of capital has approached, and in some years (1974, 1975, and 1976) even surpassed, that of the industrials.

3. Another view of the relative positions of the utilities versus the industrials is revealed from the risk premiums graphed in Figure 5. Here we see (1) that the industrials' risk premiums exhibited no pronounced trend from 1966 through 1974, but that the trend has been up since 1974, and (2) that the utilities have generally trended up since the mid-1960's, although, after reaching a peak in 1975, the utilities' upward trend has essentially ceased.

Some Caveats

As noted above, the validity of our nonconstant approach is critically dependent upon the assumption that the Value Line analysts' forecasts are substantially the same as those of the average investor in the market, or the market consensus. For large groups of companies, this assumption seems reasonable at first glance, but it can certainly be questioned, and a potential bias does exist whenever the forecasts of any single organization are used as a proxy for the views of investors in general. If at some point in time Value Line as an organization tended to be optimistic or pessimistic relative to other organizations about the future state of the general economy, or about a subset such as the electric utilities, then Value Line's expected rates of return, and consequently risk premiums based on Value Line data, would not reflect the views of investors in general. It would obviously be useful to check our nonconstant growth risk premiums, which were based on Value Line data, against results based on other analysts' data. Unfortunately, no other published forecasts on a historical basis could be located. However, we hope to obtain forecasts made by analysts of other organizations (bank trust departments, mutual funds, life insurance companies, and brokerage houses) at some future date. If we could obtain a good set of such forecasts, they could be averaged to form an estimate of the market consensus and then used just as we used the Value Line data. One could certainly place more confidence in information based on such an average than on the forecasts of a single organization such as Value Line.

Table 4. Value Line Risk Premiums, 1966-1980

Beginning of Year	Dow Jones 29 Industrials		Dow Jones 11 Electrics		3-Year Centered Moving Average	
	Value Weighted k	Risk Premium	Value Weighted k	Risk Premium	Industrials	Electrics
1966	9.56%	5.06%	8.11%	3.61%	-	-
1967	11.57	6.81	9.00	4.24	5.61%	3.98%
1968	10.56	4.97	9.68	4.09	5.62	3.93
1969	10.96	5.08	9.34	3.46	5.12	3.89
1970	12.22	5.31	11.04	4.13	5.11	4.04
1971	11.23	4.95	10.80	4.52	5.12	4.39
1972	11.09	5.09	10.53	4.53	5.18	4.82
1973	11.47	5.51	11.37	5.41	5.23	5.50
1974	12.38	5.09	13.85	6.56	5.84	6.90
1975	14.83	6.92	16.63	8.72	5.70	7.01
1976	13.32	5.09	13.97	5.74	6.11	6.71
1977	13.63	6.33	12.96	5.66	6.10	5.65
1978	14.75	6.88	13.42	5.55	6.60	5.74
1979	15.50	6.59	14.92	6.01	6.61	5.92
1980	16.53	6.35	16.39	6.21	-	-
Average	12.64%	5.74%	12.13%	5.23%		

FIGURE 4. EXPECTED RATES OF RETURN ON DOW JONES INDUSTRIALS AND ELECTRICS, NONCONSTANT (VALUE LINE) MODEL, VERSUS TREASURY BOND YIELDS, 1966-1980

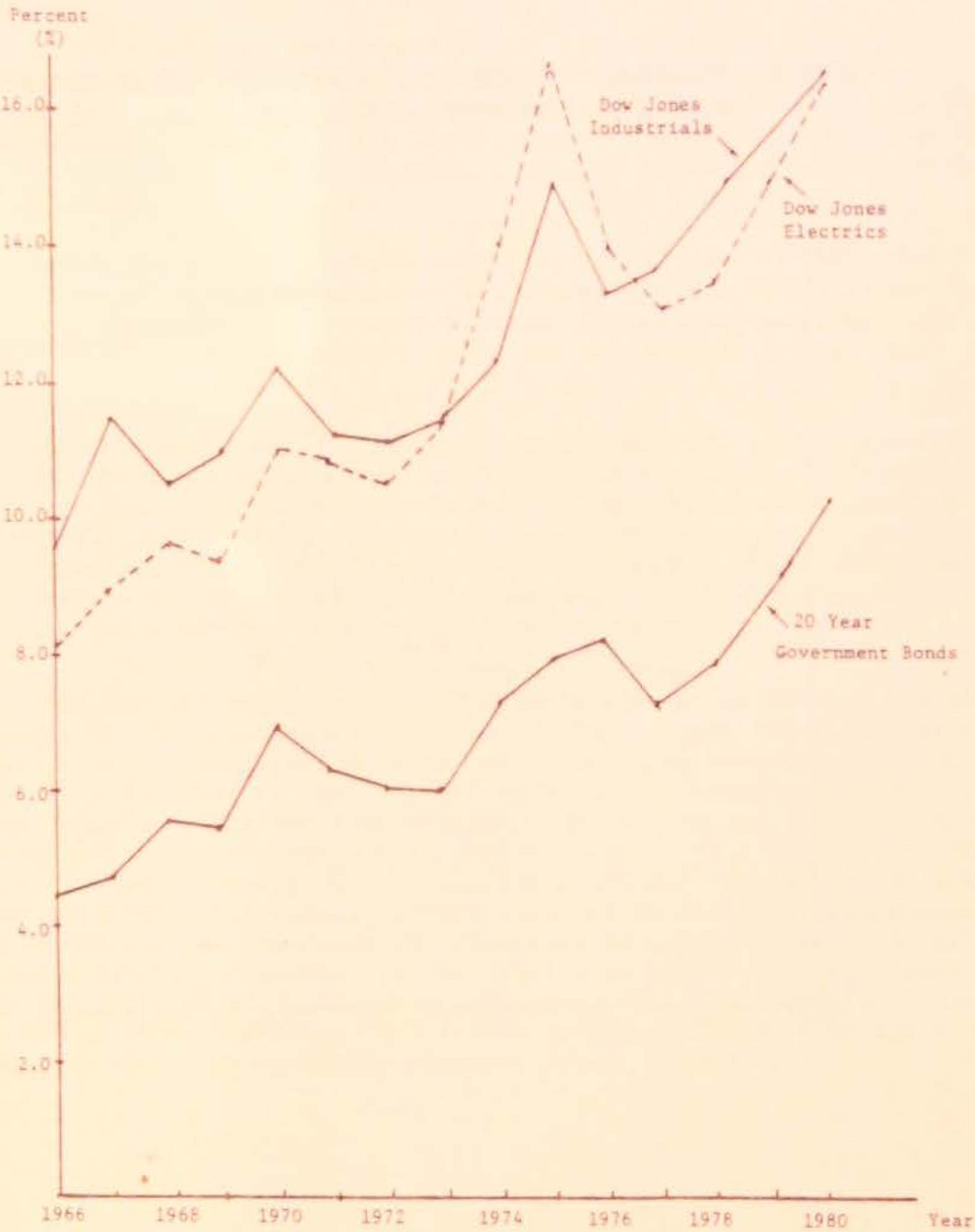
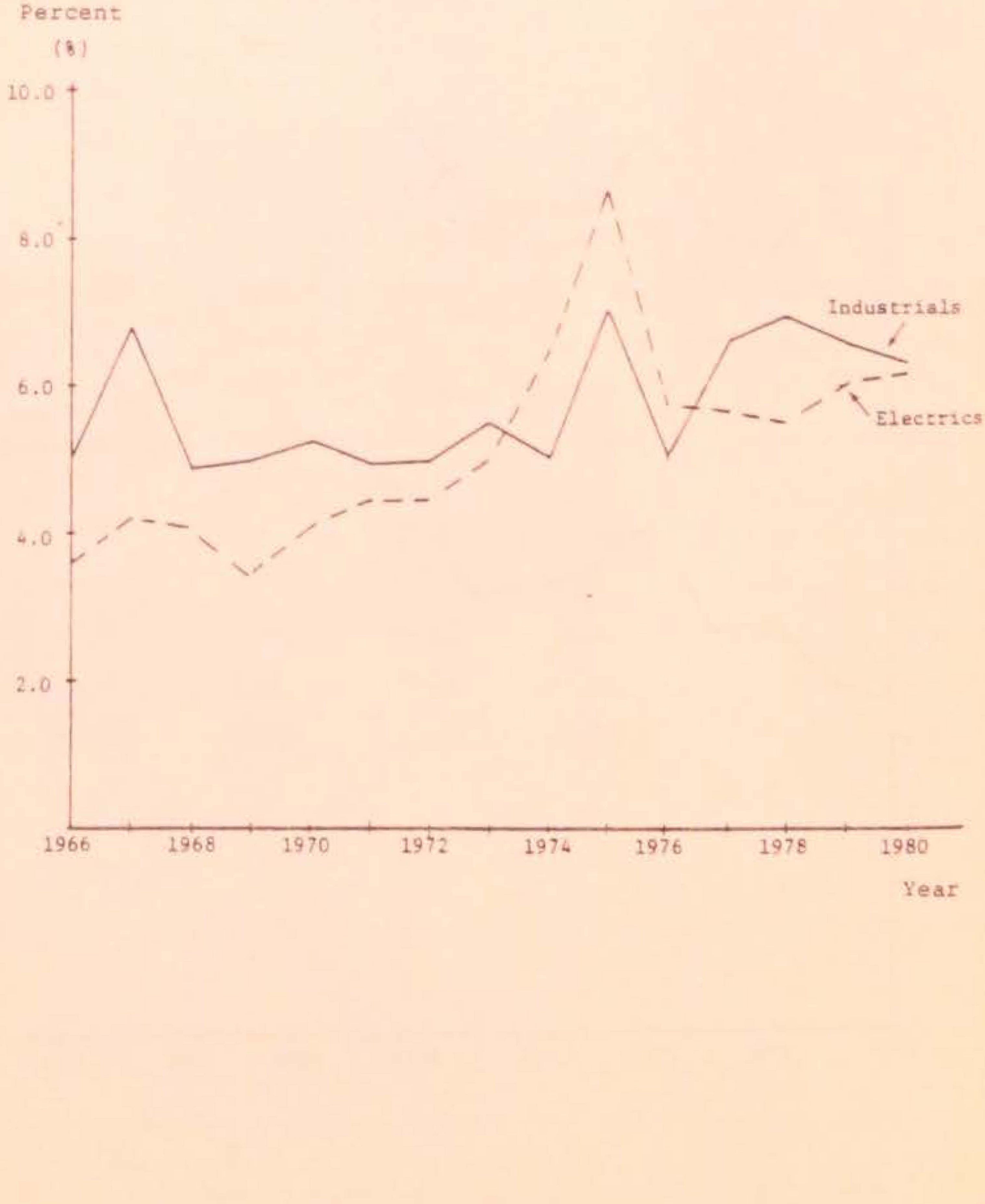


Figure 5. Estimated Risk Premiums for Dow Jones Industrials and Electrics, Nonconstant (Value Line) Model, 1966-1980



CONSTANT GROWTH VERSUS NONCONSTANT GROWTH RISK PREMIUMS

Figure 6 shows the Dow Jones risk premiums estimated by the constant and nonconstant growth models, along with risk premiums for the S&P 399 as estimated by the constant growth model. The lower panel plots moving averages, which smooth out variations somewhat and thereby facilitate certain types of comparisons. These points are suggested by the graphs:

1. It is clear that industrial firms' risk premiums, no matter whether they are measured by the constant or the nonconstant growth models, whether they are for the Dow Jones 29 or the S&P 399, or whether they are based only on historical data or on the Value Line analysts' forecasts, tend to track one another rather closely.

2. Using the constant growth model, it is also very clear (from Panel b) that risk premiums are higher for the S&P 399 than for the Dow Jones 29. Because of data limitations, we are unable to compare these two samples using the nonconstant (Value Line) procedure.

3. For the Dow Jones 29, it is apparent that risk premiums estimated by the nonconstant model, with Value Line analysts' forecasts, are far more stable than those based on the constant growth model using only historic accounting data. Apparently, the analysts "look over the valleys and through the peaks" when making their estimates for future growth rates, and this stabilizes both the expected returns on equity and the estimated risk premiums.

The S&P 399 would provide a better basis for estimating the risk premium for an "average NYSE company." At the same time, one might argue that the nonconstant model, with the Value Line data, is conceptually superior to the constant growth model using Compustat data. Thus, the "best" market risk premium might be the one for the S&P 399 based on the nonconstant model. Unfortunately, data limitations have kept us from examining this particular premium.[1] Therefore, as the best available alternative, we are inclined to use the risk premium estimated for the Dow Jones 29, increased by approximately 0.5 percentage points to account for the apparently higher risk premiums on the S&P 399. Thus, in January, 1980, the market risk premium would appear to be in the range of 6 to 7 percentage points, with the midpoint of 6.5 representing the most likely estimate.

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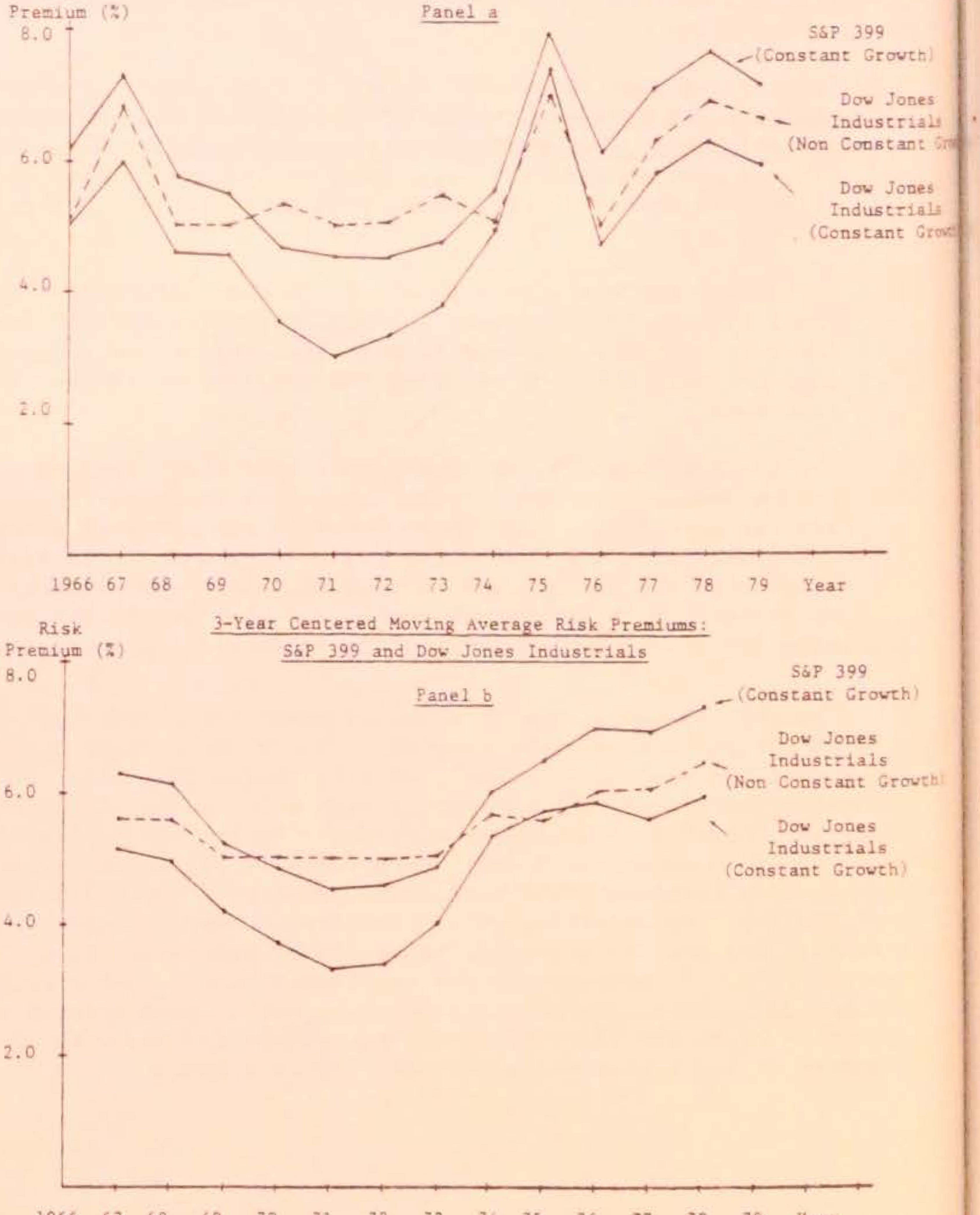
[1] We have conducted experiments along these lines, using the Value Line data tapes, but the tapes do not provide the information necessary to calculate risk premiums over time.

Figure 6.

Annual Risk Premiums: S&P 399 and Dow Jones Industrials



RISK PREMIUMS FOR INDIVIDUAL COMPANIES

Our major interest in risk premiums is to use them to help estimate the cost of equity for individual companies. Given an accurate estimate of the market risk premium, and a judgment about whether investors consider a particular company to be of high, average, or low risk, we could adjust the market risk premium for the company, then add the current bond rate to obtain an estimate of the company's cost of equity. The company's risk position could be ascertained in various ways, as could the size of the adjustment for high and low risk firms. For the industrials, one might use the CAPM, but this would not, in our judgment, be appropriate for the utilities.[1]

We have considered the adjustment process at some length, but to date we have not been able to develop a methodology which provides what we consider to be highly reliable estimates of company-specific risk premiums. First, we concluded that it is completely inappropriate to estimate company risk premiums directly with the constant growth model. Aggregated data do appear to provide reasonable estimates of the market risk premium, but the data on individual companies are too unstable to use except after averaging to eliminate random errors in the company data. An examination of the raw data showed that while the majority of the companies had risk premiums that were not obviously unreasonable, in some years a few of the smaller members of the S&P 399 had calculated risk premiums that were negative, while others had premiums of 20 percent or more.[2] Because of these problems, we

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[1]See Eugene F. Brigham and Roy L. Crum, "On the Use of the CAPM in Public Utility Rate Cases," Financial Management, Summer 1977, pp. 7-17, and "Reply to Comments on 'Use of CAPM in Public Utility Rate Cases,'" Financial Management, Autumn 1978, pp. 72-76.

[2]The negative premiums arise if a firm has (1) low dividends, hence a low dividend yield, and (2) an abnormally low rate of return on equity, which produces a low or even negative growth rate. If this condition holds for several years, especially during the last two years to which our formula gives special weight, then the combination of dividend yield plus growth rate can be less than the yield on Treasury bonds, producing a negative risk premium. This situation is always regarded as being temporary--investors expect the ROE to return to normal levels, pulling up earnings, dividends, and the growth rate.

Large risk premiums can arise in two ways. First, a company may have a very high ROE, say 30 percent, and may retain most of its earnings, which would give it a k value of close to 30 percent. Subtracting R_F would produce a risk premium of over 20 percent. If the high ROE is a temporary cyclical phenomenon, then our smoothing process would reduce the risk premium, but if the high ROE persists for four years, we would report high premium. While companies can and do earn very high ROE's in the short-run, it is unrealistic to project a continuation of an ROE of over 20 percent, combined with a low payout ratio, over the long-run. The second factor that can cause high risk premiums is that, on rare occasions, some of the S&P 399 companies have had large writeoffs, which have reduced reported equity to low levels. Later, "normal" profits are divided by the very low reported equity values, and this results in very high reported ROE's and risk premiums.

abandoned the idea of estimating individual company risk premiums using the constant growth model.[1]

With the nonconstant growth approach, using Value Line data, the problem of data instability is generally not serious, so it is feasible to make direct, company specific estimates of the risk premiums.[2] For instance, in the preceding example for the Southern Company, we found that the nonconstant growth DCF cost of equity in late May, 1980, was 15.5%. The risk premium for Southern Company is thus estimated to be

$$RP = k_i - R_F = 15.5 - 10.2 = 5.3\%.$$

Here R_F is the yield on a twenty year government bond in late May, 19[illegible] This same general approach could be used for any of the 1,700 companies followed by Value Line.

However, as noted above, the validity of this approach is critically dependent upon whether or not the Value Line analysts are representative of the views of investors in general. On an individual company basis, and for the current period, it may be possible to obtain forecasts such as those made by Value Line, but by other influential securities organizations. If a number of such forecasts could be obtained, they could be averaged to form a proxy for the views of investors in general. The larger the number of separate forecasts, the higher our confidence in the resulting average risk premium would be.[3]

---

[1]We should note, however, that the premiums based on averaged data for individual companies were generally quite similar to those based on aggregated data. The highs and the lows tended to offset one another. However, in some instances the explosive nature of ratios (dividing a number by a number close to zero produces a very large quotient) resulted in risk premiums (plus or minus) of over 100 percent. These were always found for smaller companies; hence they did not get much weight in the market-weighted average risk premium, and, in addition, the extreme pluses and minuses tended to cancel one another. Nevertheless, we still feel much more comfortable with the aggregated data premiums as reported in the present study.

[2]However, Value Line may be more or less optimistic about the Company than the average investor; this could cause the Company's risk premium and estimated cost of equity to be measured incorrectly.

[3]It should also be noted that Value Line judges some stocks to be better "buys" than others. This suggests that Value Line's analysts feel that all stocks are not in equilibrium--that some are above the Security Market Line (SML) while others are below the SML. This being the case, it may be that Value Line is more optimistic than the average investor about the growth prospects for the companies it ranks highest and less optimistic about those which it ranks lowest. This point does not influence the validity of Value Line data for determining the average risk premium, but it reinforces questions about using Value Line to estimate risk premiums for individual companies.

OTHER STUDIES OF RISK PREMIUMS

As noted earlier, Ibbotson and Sinquefield have studied the historic relationship between returns on stocks and bonds, and Benore has studied forward-looking risk premiums on a survey basis. Also, Malkiel examined risk premiums using a methodology very similar to ours.[1] Malkiel estimated the expected rate of return on the 30 Dow Jones industrial stocks in each year from 1960 to 1977. He based his growth rate forecast on Value Line earnings growth forecasts, and he used 10-year maturity government bonds as a proxy for the riskless rate. Further, he assumed that each company's growth rate would, after the initial 5-year period, move toward the long-run real national growth rate (3 to 4% when his study was prepared). Malkiel reported that he tested the sensitivity of his results against a number of different types of changes, but, in his words, "The results are remarkably robust and the estimated risk premiums are all very similar to those displayed on the chart."[2]

Figure 7 shows a plot of Malkiel's risk premiums together with ours for the Dow Industrials, using Value Line data. Our years have been shifted back one to make our data comparable to Malkiel's. Our risk premiums are generally higher than Malkiel's in the earlier years, but the two studies converge after 1973. The differences could have arisen for these reasons: (1) Malkiel restricted his terminal growth rate to the 3 to 4% range; (2) he included AT&T while we excluded it; (3) the Dow Jones Industrials included Chrysler and Esmark when Malkiel did his study, but these two companies had been replaced by IBM and Merck when we did ours; (4) he used 10-year Treasury bonds while we used 20-year maturities; and (5) the format of the Value Line reports has tended to change somewhat over time, and we may have interpreted earlier year data differently than Malkiel did.

Malkiel's risk premium analysis was not the central focus of his study--his focus was on reasons why the United States has lagged behind certain other nations in expanding and improving its stock of physical capital. He only calculated and discussed risk premiums and the accompanying rise in the cost of equity capital as one small part of his discussion of the United States' lag in aggregate capital expansion. His data (and ours) certainly support his major contention. At the same time, Malkiel's data also support our estimates, especially in the more recent years.

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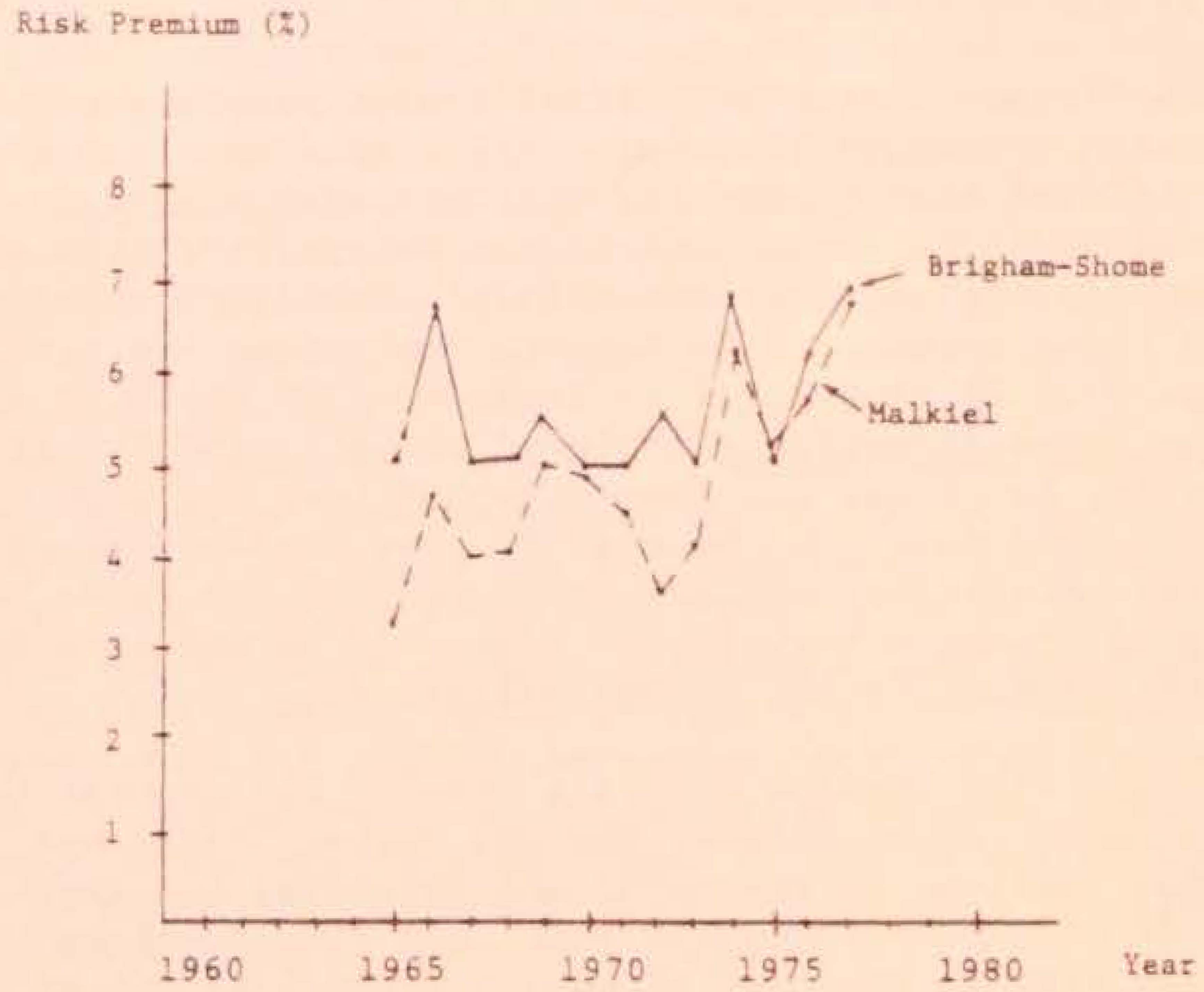
[1] B. G. Malkiel, op. cit.

[2] Ibid., p. 300.

Figure 7

Comparison with Malkiel's Risk Premiums



Source: Malkiel, Op. Cit., Figure 2; Brigham-Shome, Table 4.

SUMMARY

The purpose of this paper was to estimate a market risk premium for use as a basing point in the determination of the cost of equity for a firm. In the past, most analysts who required a risk premium for their work have used historic holding period returns such as those provided by Ibbotson-Sinquefield, or else used risk premiums based on survey data such as those of Benore. Malkiel is the major exception--he used forward-looking risk premiums designed to capture expectations about future returns, and his methodology and results are similar to ours.

We used both the DCF constant growth model (the Gordon model) and a nonconstant version of the DCF model to determine expected rates of return on samples of industrial and utility stocks, over the period 1964-1980. From these expected annual returns we subtracted the yield to maturity on 20-year U.S. Treasury bonds to obtain estimates of the market risk premium. Risk premiums for the industrials declined slightly from the early 1960's through 1973, after which time the trend has been generally upward. The electric utilities had much lower risk premiums than the industrials in the 1960's, but the utilities' riskiness both in absolute terms and relative to the industrials has trended up since the mid-1960's. As a result, the utilities' cost of equity has been rising faster than that of the industrials, and today there does not appear to be much difference between the cost of equity to industrials and to utilities.

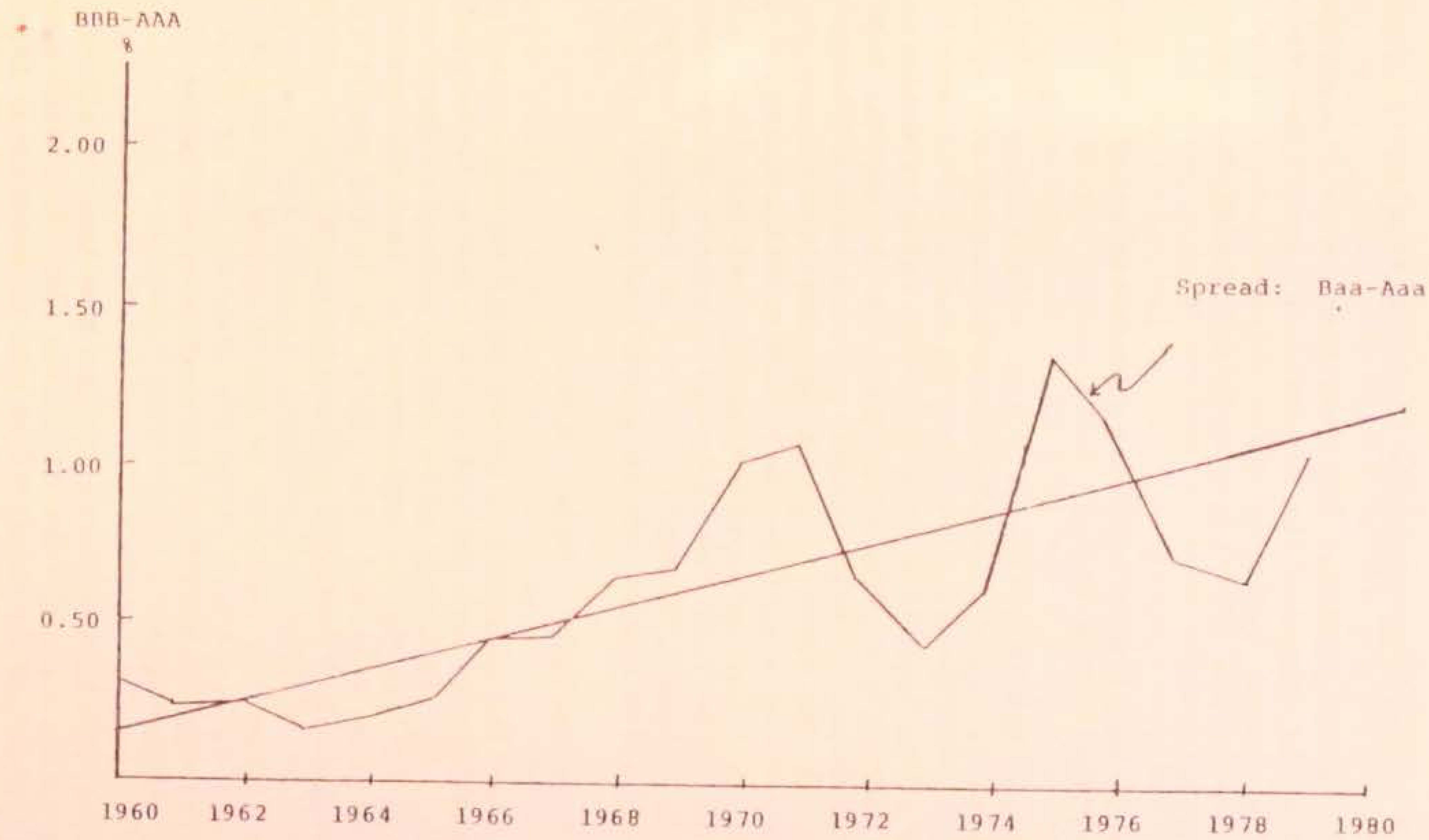
Appendix A. YIELD DIFFERENTIALS ON VARIOUS TYPES OF BONDS
1960-1979
(Average of Monthly Values)

YEAR	GOVERNMENT BONDS SHORT TERM	GOVERNMENT BONDS LONG TERM	UTILITY BONDS AAA	UTILITY BONDS AA	UTILITY BONDS A	UTILITY BONDS BBB	YIELD SPREADS AAA -L.T. GOVT'S	YIELD SPREADS AA -AAA	YIELD SPREADS A -AAA	YIELD SPREADS BBB -AAA	YIELD SPREADS A -AA	YIELD SPREADS BBB -AA	YIELD SPREADS BBB -A
1960	3.85	3.99	4.51	4.54	4.66	4.82	.52	.03	.15	.31	.12	.28	.16
1961	3.51	3.90	4.47	4.52	4.61	4.70	.57	.05	.14	.23	.09	.18	.09
1962	3.32	3.95	4.29	4.37	4.42	4.53	.34	.08	.13	.24	.05	.16	.11
1963	3.56	4.02	4.29	4.32	4.37	4.45	.27	.03	.08	.16	.05	.13	.08
1964	3.84	4.17	4.41	4.44	4.50	4.60	.24	.03	.09	.19	.06	.16	.10
1965	4.07	4.23	4.52	4.55	4.63	4.77	.29	.03	.11	.25	.08	.22	.14
1966	4.95	4.68	5.19	5.23	5.37	5.64	.51	.04	.18	.45	.14	.41	.27
1967	4.69	4.90	5.61	5.67	5.80	6.07	.71	.06	.19	.46	.13	.40	.27
1968	5.41	5.33	6.24	6.36	6.56	6.88	.91	.12	.32	.64	.20	.52	.32
1969	6.42	6.22	7.22	7.39	7.57	7.90	1.00	.17	.35	.68	.18	.51	.33
1970	7.19	6.75	8.11	8.35	8.70	9.12	1.36	.24	.59	1.01	.35	.77	.42
1971	5.32	5.94	7.54	7.71	8.24	8.62	1.60	.17	.70	1.08	.53	.91	.38
1972	5.83	5.67	7.41	7.53	7.80	8.05	1.74	.12	.39	.64	.27	.52	.25
1973	6.88	6.12	7.72	7.83	8.03	8.17	1.60	.11	.31	.45	.20	.34	.14
1974	7.75	6.59	8.45	8.63	8.75	9.08	1.86	.18	.30	.63	.12	.45	.33
1975	7.37	8.21	8.84	9.17	9.50	10.21	.63	.33	.66	1.37	.33	1.04	.71
1976	6.50	7.87	8.50	8.82	9.05	9.64	.63	.32	.55	1.14	.23	.82	.59
1977	6.21	7.69	8.14	8.44	8.60	8.86	.45	.30	.46	.72	.16	.42	.26
1978	8.24	8.46	8.83	9.06	9.20	9.48	.37	.23	.37	.65	.14	.42	.28
1979	9.89	9.27	9.64	9.97	10.17	10.69	.37	.33	.53	1.05	.20	.72	.52
AVERAGE	5.74	5.90	6.69	6.85	7.03	7.32	.80	.15	.33	.62	.18	.47	.29
STANDARD DEVIATION							.54	.11	.20	.36	.12	.26	.17

Source: Standard & Poor, Security Price Index, 1979.

Figure A-1

RISK PREMIUMS ON TRIPLE B BONDS



DETERMINATION OF A TARGET MARKET TO BOOK VALUE RATIO FOR A PUBLIC UTILITY IN AN INFLATIONARY ENVIRONMENT

Robert H. Litzenberger
C.O.G. Miller Distinguished Professor of Finance
Stanford University

I. Market Price: The End Product of the Regulatory Process

The economic rational for regulating a public utility is to capture for the consumer the economies of scale associated with sanctioning a legal monopoly while allowing the shareholder to earn a return commensurate with the return on competitive enterprises having corresponding risks.

This is consistent with the frequently cited passage of the Hope decision (1944) which states:

> "The rate-making process...,i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and consumer interests. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends in the stock. By that standard the return to the equity owner should be comensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." (Hope 603)

The Hope decision further states:

> "...that the commission is not bound to the use of any single formula or combination of formulae in determining rates. Its rate making function, moreover, involves the making of 'pragmatic adjustments... Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling." (Hope 603)

Thus the method employed is not an issue so long as the result is "just and reasonable." From the prospective of a public utilities the only relevant "result" is the impact on the price of the public utilities common stock.

In most regulatory jurisdictions the overall allowed rate of return is an accounting rate of return and is applied to a rate base, which is approximately equal to assets at historical cost less accumulated depreciation. In this context, the setting of an allowed rate of return on book value should be viewed by the regulatory commission as the method employed to achieve a "just and reasonable" market price for the public utility's common stock.

If the regulatory commission were to consistently set the allowed rate of return on book value equal to the rate of return that investors require on market value (the cost of equity capital), then in the long run the market value of a public utility's stock would revert to a vel approximately equal to its historical cost book value. The use a historical cost rate base does not justify the historical cost ok value as being fair value for the utility common stock. The Hope cision stresses that

"...'fair value' is the end product of the process of rate making and not the beginning." (Hope 601)

The setting of an allowed rate of return on historical cost book lue should, in my judgment, be viewed by the regulatory commission as e method employed to achieve a just and reasonable value for the blic utility's equity.

It also does not follow that the regulatory commission should tomatically view the current market price of the public utility as a st and reasonable market value. In an efficient capital market blicly available information about a public utility's future profits uld be reflected in the market price of its stock. It would, there-re, be circular to establish rates that would maintain the current ice of the firm's stock when that price reflects investors' expecta-ons concerning the rates the regulatory commission will allow. Past te decisions that are either over-generous or confiscatory would be flected in a high or a low current stock price. If the regulatory mmission were to automatically view the current stock price as a ust and reasonable" market value, the regulatory process would be lying on its own boot straps for support without any economic under-nning. The Hope decision stated that

"The heart of the matter is that rates cannot be made to depend upon 'fair value' when the going enterprise depends upon earnings under whatever rates may be anticipated." (Hope 601)

The market value of a public utility's equity is equal to the esent value of the future returns to its shareholders. A just and asonable market value for a public utility is the market value that commensurate with the discounted value of the return to shareholders at a competitive firm of corresponding risk and size would earn.

I. Market Values of Companies in Competitive Industries and the Determination of a Just and Reasonable Market Value for a Public Utilities Common Equity

The primary economic motivation for rate of return regulation ould be to set the expected economic profit that a public utility y earn from its position as a natural monopoly at a level that is mmensurate with the expected profits earned by competitive enter-ises of corresponding risk. In a competitive industry the possi-ility of entry and exit of firms would assure that in the long run e total market value of a firm equaled the replacement cost of its oductive capacity at the most efficient technology. For example, if thin a competitive industry the market value of each firm were more an the cost of establishing its productive capacity, there would be incentive for promoters to raise capital and establish new firms. is would increase industry-wide production, thereby lowering product ices, economic profits and market values. Similarly, if within a mpetitive industry, the market value of each firm were less than the rrent cost of establishing its productive capacity, there would be an incentive to disinvest by not replacing depreciation assets. This would lower industry-wide output, thereby raising product prices, economic profits and market values. Thus, for non-regulated firms, competitive forces assure that in the long run the average ratio of the aggregate market value of these firms to the aggregate replacement cost of their assets is close to 1.0. This is the nature of the competitive system.

In the Economic Report of the President (January 1980, page 141), the ratio of the aggregate market value (equity plus debt) of non-financial corporations to the replacement cost of their assets was estimated for each of the 24 years 1955 through 1978. This ratio is called "q" and is a well-known concept in economics. The average value of these ratios was 1.004. However, there are, of course, short-run deviations from 1.004. In particular, since 1974 these ratios have all been considerably below 1.0. For the first 3 quarters of 1979, for example, the estimate was only 0.654. The Economic Report of the President (January 1978, page 70) noted that

> "...This may be an indication that it is more profitable on average to buy existing financial assets than to invest in new plant and equipment,"

Last year's Economic Report of the President (January 1979, page 129) notes that

> "...the weakest of the determinates of investment in 1978 was the ratio of market value to replacement cost of capital, which fell in response to the weakness in the stock market. Equity values have risen relatively little during the cyclical recovery for many reasons: undertainities engendered by the depth of the 1974-75 recession, the sharp disruption caused by higher energy costs, fluctuations in the exchange value of the dollar and volatile inflation rate."

Note that these economic factors affect regulated as well as non-regulated firms. However, unlike a non-regulated firm, a regulated firm must continue to invest when its "q" ratio is below 1.0.

From the perspective of a shareholder, the end product of the rate setting process is the impact on the price of the public utility's stock. For the regulatory process to properly mirror the effect that competition has on the value of an unregulated firm, in the long run the market value of the equity of a public utility should equal the value of its equity at replacement cost. Note, however, that there are substantial short-run deviations in the "q" ratio from 1.0 for competitive enterprises. It may, therefore, be deemed to be just and reasonable to allow similar short-run deviations for public utilities.

By this standard, an allowed rate of return on equity that results in a market price of the utility's common stock that implies a ratio of the market to the replacement cost of its equity that is equal to the aggregate equity "q" ratio for an appropriately selected comparable group of non-regulated firms should be deemed just and reasonable by a regulatory commission. Unlike a non-regulated firm, a public utility must continue to make capital investment when its "q" ratio is depressed. It is essential that a public utility maintain its creditworthiness, because it must be able to finance its future capital investments. It is, therefore, important that creditworthiness be one of the criteria used to select a comparable group of firms.

The procedure used to determine a just and reasonable market price should take cognizance of the fact that most firms are not financed totally with equity, and that the embedded cost of debt is used in the calculation of the overall allowed rate of return for a utility. The total market value of the firm consists of the market value of its outstanding bonds as well as its outstanding equity. Changes in interest rates affect the market value of the bonds of a regulated utility. However, its shareholders neither benefit nor lose by the change in the market price of its bonds, because the embedded cost of debt is used in the determination of the overall allowed rate of return. Since consumers bear the gains and losses associated with a utility's issuance of long-term debt, the book value rather than the market value of debt should be subtracted from the replacement cost of assets to determine a just and reasonable market price for its stock. Economic theory suggests that a just and reasonable market price of a public utility's stock would result in a ratio of the market value of its equity to the value of its equity at adjusted replacement cost, q_2, that is equal to the equity "q" ratio for a comparable group of non-regulated firms. The value of the firm's equity at adjusted replacement cost is defined as the historical cost book value of its equity plus the difference between its net plant and equipment at replacement cost and its net plant and equipment at historical cost.

The regulatory process should be consistent with a long-run market value to replacement cost ratio of 1.0. However, a regulatory commission may allow short-run deviations from 1.0 in either direction to minor actual competitive forces in the non-regulated market place. A short-run target market to book value ratio that would result in a "q_2" ratio equal to the equity "q" ratio for a sample of comparable non-regulated firm may by that standard be considered "just and reasonable."

III. Implementation: An Example

To be able to implement the previously described approach requires the choice of a sample of non-regulated firms of similar risk to the public utility. Risk has many dimensions. Two measures of risk are used widely by investors. For a large shareholder holding a widely diversified portfolio of common stocks, an individual stock's beta would be an appropriate measure of the contribution of that security to the variability of the rate of return on that portfolio. Beta measures the extent to which the rate of return on a common stock moves with the market. Beta is a widely publicized measure of risk, and estimates of betas for large number of stocks are claculated and published on a regular basis by such organizations as Merrill Lynch, Wells Fargo and Value Line. For a small shareholder holding just a few stocks, the portion of the total variability in the market rate of return on a stock that is unrelated to general movements in the market is important because the small investor's portfolio is not fully diversified. The beta measure does not capture this portion of total variability. The component of the variability of an individual stock that is attributable to movements that are unrelated to general movements in the market is called its non-systematic risk.

Both the firm's beta and its non-systematic risk determine the total variability of its rate of return and, therefore, influence the firm's risk of insolvency and its ability to attract capital. However, the financial integrity of the firm and its ability to raise capital on reasonable terms cannot be accurately assessed by only considering published measures of beta and non-systematic risk. For example, many real estate investment trusts having serious financial problems have low published betas and non-systematic risk. The implementation of the comparable earnings approach, therefore, should also take cognizance of measures which relate directly to the financial integrity of the firm and its ability to attract capital. Bond ratings and stock rankings are additional measures of the ability of the firm to attract capital on reasonable terms.

The Center for Research in Security Prices (CRSP) at the University of Chicago and COMPUSTAT, a data service provided by a subsidiary of Standard & Poor's, maintain files on market rates of return and on annual accounting data, respectively, for firms listed on the NYSE. Using the COMPUSTAT file, I first selected non-financial firms in non-regulated industries with common equity greater than $100 million for 1978. I excluded financial industries from my survey because financial institutions are not required to report the replacement cost of their assets. I selected only firms with common equity book values greater than $100 million in order to focus the analysis on larger firms that report replacement costs of their assets.

Of the firms listed on the NYSE, 444 met these initial criteria. I calculated the beta and non-systematic risk of each of these 444 firms using monthly rates of return from the CRSP data file for the period January 1974 to December 1978. I also identified the Standard & Poor's stock ranking for each of these firms. My first comparable risk standard was that the firm have a beta that is within the lowest decile.

My second comparable risk standard was that the firm have a non-systematic risk within the lowest decile. Finally, in my judgment, an A stock ranking is an indicator of a financially stable firm. My third standard was, therefore, that the firm have a Standard & Poor's stock ranking of A+, A or A-.

There are only 10 firms that met all 3 of these risk standards. A larger and more representative sample is obtained by requiring firms to meet only 2 out of 3 of the standards. There are 61 such firms. This sample is large and contains a sufficiently broad industry diversity to be an appropriate standard for determining the fair rate of return on a public utility's equity.

The comparable equity "q" ratio for this sample of 61 non-regulated, non-financial firms having risks comparable to a typical public utility is 0.665. The recommended target market to book value ratio for a hypothetical public utility, XYZ Public Utility, is illustrated below.

Historical cost book value of equity (000)	\$100,000
Plus:	
Difference between net plant and equipment at replacement cost and at historical cost (000)	+ 80,000
Value of equity at adjusted replacement cost	\$180,000
Times:	
Equity "q" ratio for comparable firms short target market value of equity (000)	x 0.665
	\$119,700
Divided by:	
Historical cost book value of equity (000)	÷ 100,000
Recommended target market to book ratio	1.2

TWELFTH SESSION, Thursday, May 22 - 10:15 a.m.

Concurrent Session F-1

FINANCIAL REPORTING WITH PRICE LEVEL CHANGES

CHAIRMAN: John F. Utley

SPEAKERS: Larry McManus
Controller and Treasurer
Western LNG Terminal Associates

W. J. Johnson
Controller
El Paso Electric Company

Joe A. Jones
Supervisor Manager, Public Utilities Department
Deloitte Haskins & Sells

FINANCIAL REPORTING WITH PRICE LEVEL CHANGES

Larry G. McManus
Controller/Treasurer
Western LNG Terminal Associates

Good morning. It is a pleasure to appear before you and discuss Financial Reporting and Changing Prices.

The subject of changes in general prices and the impact on measurement and comparability of financial statement elements is certainly not a new concern. The subject has been discussed widely in accounting literature and extensively studied by the various accounting standard-setting authorities over the years. Most of the early discussions dealt with individual elements such as depreciation and cost of goods sold. In June, 1969 the Accounting Principles Board released Opinion #3, "Financial Statements Restated for General Price Level Changes" which recommended but did not require that historical dollar financial statements be supplemented by general price level information. As you know this recommendation was generally ignored.

The Financial Accounting Standards Board first addressed the issue of changing prices in a Discussion Memorandum published in January, 1974 entitled, "Reporting the Effects of General Price Level Changes in Financial Statements." The Discussion Memorandum asked if reporting the effects of general price level changes should be required as supplementary information. Most utilities advised the Board that reporting the effects of price level changes should remain optional as required by Accounting Principles Board Opinion #3 at least until the Conceptual Framework for Accounting and Reporting Project is completed.

In December, 1974 the Financial Accounting Standards Board moved to the next step and published an Exposure Draft entitled, "Financial Reporting in Units of General Purchasing Power." This proposed statement would have required supplementary disclosure of specified financial information stated in units of general purchasing power. Most utilities questioned the need and value of financial data restated in units of general purchasing power and again urged the Board to defer action until the Conceptual Framework for Financial Accounting and Reporting Project is completed. The gas industry's response explained that price level induced "purchasing power gains" related to debt outstanding benefit the ratepayer under historical cost regulation. The Exposure Draft generated a substantial reaction and in November, 1975 the Board announced that a final statement would not be issued pending additional analysis of the results of a field test of the provisions. In June, 1976 the Board again deferred action on this December, 1974 Exposure Draft.

In March, 1976 the Securities and Exchange Commission issued Accounting Series Release 190, "Notice of Adoption of Amendments to Regulation S-X Requiring Disclosure of Certain Replacement Cost Data." ASR 190 requires certain publicly held companies to disclose replacement cost information about inventories, cost of sales, productive capacity and depreciation. The SEC did not distinguish utilities from other industries. When SEC proposed to require disclosure of replacement cost they received 360 responses and 90% opposed the requirement. The primary arguments against the requirement were cost, softness of the supporting data, and the lack of uniform procedures. The SEC responded to these objections by limiting the application of the requirement to companies with large capital investments; appointing an Advisory Committee to develop guidelines for compliance; and providing a safe harbor intended to assure that no violation of the security laws and regulations would occur due to errors in the projections if the data was reasonably developed, disclosure was adequate, and evidence of a good faith attempt to comply with the requirement could be presented. Every indication supports a conclusion that users of financial statements have ignored the replacement cost disclosure.

In December, 1978 the Financial Accounting Standards Board published an Exposure Draft entitled, "Financial Reporting and Changing Prices." This proposed statement concluded that the primary focus should be on financial statements based on historical cost, but would require certain large, publicly held enterprises to disclose supplementary information about the effects of changing prices on income from continuing operations on an historical cost/constant dollar basis or on a current cost basis. Enterprises that present current cost information would also be required to present information on holding gains and losses, net of inflation; and a statement of the current cost of inventory, property, plant and equipment at the end of the fiscal year. Most utilities supported the Board's conclusion that the primary focus should be on financial statements based on historical cost and argued that regulated utilities should not be required to make the supplemental disclosure in the manner proposed by the Board because of the unique economic circumstances of regulation. The utilities argued that the recoverable value of utility property is the value allowed by the regulatory authorities in rate base which normally is the original cost net of accumulated depreciation. The Board was advised that since utility return is established by the regulatory authority by determining an allowed rate of return and applying that rate to rate base, it would not be appropriate to impact the income from continuing operations by changing prices unless the compensating effects on revenue are also recognized.

In September, 1979 the Financial Accounting Standards Board dropped the bomb by issuing Statement of Financial Accounting Standards No. 33. Needless to say utility responses had little impact on the statement. As a matter of fact, the proposed statement was less onerous than Statement #33 since the proposed statement provided a choice between constant dollar and current cost, whereas Statement #33 requires both.

I am sure you are generally familiar with the supplementary disclosure required by Statement #33. Basically enterprises with total assets less accumulated depreciation in excess of $1 billion; or inventories, property, plant and equipment before accumulated depreciation in excess of $125 million must disclose the following as supplementary information:

> Income from continuing operations adjusted for general inflation for the current fiscal year. Referred to as the historical cost/constant dollar basis.
>
> Income from continuing operations adjusted for changes in specific prices. Referred to as the current cost basis.

The purchasing power gain or loss on monetary items for the current fiscal year.

The current cost amounts of inventory, property, plant and equipment as of the end of the current fiscal year.

Increases or decreases for the current fiscal year in the current cost amounts of inventory, property, plant and equipment, net of inflation. This is the change in specific price compared to general prices.

Notes to the supplementary data disclose the following information:

Principal types of information or sources of information used as a basis of calculation of the current cost of inventory, property, plant and equipment, cost of goods sold and the related depreciation, depletion and amortization expense.

Any differences between the depreciation methods, estimates of useful lives, and salvage values used for the historical cost/constant dollar and current cost depreciation, and the methods and estimates which were used for depreciation of the primary financial statements.

In addition to these disclosures for the current fiscal year, the following disclosures are required to be made for each of the five most recent fiscal years.

Net sales and other operating revenues in historical cost/nominal dollar amounts.

Cash dividends declared per common share.

Market price per common share at fiscal year end.

Disclosure of the following items is also required in the five year summary of selected financial data but amounts for fiscal years ended before December 25, 1979 are not required.

Income from continuing operations adjusted for general inflation.

Income from continuing operations adjusted for general inflation per common share.

Net assets adjusted for general inflation at fiscal year end.

Purchasing power gain or loss on net monetary items.

Consumer price index for each year in the summary.

The current cost disclosure may be deferred until reports for fiscal years ending on or after December 25, 1980.

Of all the disclosures I have been outlining above, all are fairly specific and generally well defined in the statement except for those relating to current cost information and the development of current cost measurements for inventory, property, plant and equipment which must be at current cost or lower recoverable amount.

Under the provisions of Statement #33 utilities must consider the need to adjust for recoverable amounts. The statement defines the term recoverable amount to mean the current worth of the net amount of cash expected to be recoverable from the use or sale of an asset. The statement requires that if the recoverable amount is materially and permanently lower than historical cost in constant dollars or current cost, the recoverable amount shall be used as a measure of the assets and of the expense associated with the use or sale of the assets.

The statement further provides that recoverable amounts may be measured by considering the net realizable values or the values in use of the assets concerned. Since no established market exists for most utility plant clearly the value in use measurement applies. Statement #33 states that value in use is equal to the expected future cash flows at an appropriate discount rate that allows for the risk of the activities concerned. Clearly for a regulated utility where the regulatory authority uses original cost in determining rate base, the recoverable amount is the net plant value in nominal dollar amounts since that is the present value of expected future cash flows to be generated by the use of the asset.

The Board clearly recognizes this fact for regulated utilities in paragraph 64 of the statement. I quote:

> "An enterprise that is subject to rate regulation or other form of price control may be limited to a maximum recovery through its selling prices, based on the nominal dollar amount of the historical cost of its assets. In that situation, nominal dollar/historical costs may represent an appropriate basis for the measurement of the recoverable amounts associated with the assets at the end of the fiscal year. Recoverable amounts may also be lower than historical costs."

I suppose this could be considered a major accomplishment for the utility industry. An authoritative accounting body finally recognized a reality of rate regulation. But don't celebrate too soon because the Board goes on from there to clearly demonstrate a lack of understanding. I quote:

> "However, cost of goods sold and depreciation, depletion, and amortization expense shall be measured at historical cost/constant dollar amounts (in measurements of historical cost/constant dollar income from continuing operations) or at current cost (in measurements of current cost income from continuing operations) provided that replacement of the service potential provided by the related assets would be undertaken, if necessary, in current economic conditions; if replacement would not be undertaken, expenses shall be measured at recoverable amounts."

The Board would have us report asset values at recoverable amounts or original cost and report earnings from continuing operations with depreciation based on current cost or constant dollar values of assets without any adjustment of revenue. This position assumes both irresponsible regulation and irresponsible management of the regulated entity. Clearly, if assets are replaced, the replacement cost becomes the original cost at that time and is recoverable through future revenues.

The Board also determined that the purchasing power gain or loss on net monetary items should not be included in arriving at the adjusted income from continuing operations. The statement requires the gain or loss to be reported as a separate item. Obviously, the Board fails to recognize that to the extent assets are financed by borrowed funds and recovery of the investment in assets is limited to original cost there is no net gain or loss in the purchasing power to the equity investors. The increase in asset value to the extent financed by debt is offset by the holding gain on the debt. At minimum these items must be offset to avoid a gross distortion of income from continuing operations. Reference to paragraphs 173-176 of Statement #33 clearly illustrates the Board's failure to address the issue. These paragraphs are in the section entitled, "Basis for Conclusions" and are intended to support the Board's conclusion on the manner in which Statement #33 applies to regulated businesses. Not only is the effect of debt ignored in the discussion but the example which illustrates alternative disclosures considered for regulated businesses assumes no liabilities.

A group of representatives from Edison Electric Institute proposed a form of disclosure to the Board which partially corrects for this misstatement by moving the write-down of assets to recoverable value out of the computation of income from continuing operations. While not the best solution, this approach is better than the disclosure recommended by the Board in Statement #33. The Board published this alternative in the booklet entitled, "Illustrative Disclosure - Blank Electric Utility Company" but included a footnote which indicates what income from continuing operations would be if the write-down was included.

We may still have an opportunity to modify the Board's position on the requirements of Statement #33 as applied to regulated utilities through the Board's Discussion Memorandum, "Effect of Rate Regulation on Accounting for Regulated Enterprises" published in December, 1979. Public hearings on this Discussion Memorandum will be held May 28 and 29, 1980 in Chicago. Many utilities addressed the changing prices issue in responses to this Discussion Memorandum in an attempt to focus the Board's attention on the economics of the utility industry and how they relate to the disclosure of the impact of changing prices. I believe we can demonstrate how the requirements of Statement #33 applied to regulated utilities fail to meet the objectives of the Board as stated in Statement #33 and the weaknesses in the logic stated by the Board in support of their conclusions on disclosure by utilities.

A final comment on the application of Statement #33 is the treatment of Construction Work In Progress (CWIP). CWIP includes elements which are replacement of current service potential and elements involving expansion of current service potential. The treatment of CWIP must be consistent with the treatment of AFUDC and interest charges in measuring the income from continuing operations. AFUDC must be included in the determination of income from continuing operations if total interest charges are included. Therefore, CWIP should be considered a non-monetary asset but restatement to constant dollar or current cost is not necessary. This conclusion is based on the determination that the elements of CWIP which represent a replacement of current service potential have already been considered by restating plant in service. The elements of CWIP that represent an expansion of current service potential should not be restated since the objective and provisions of Statement #33 clearly deal with current income from continuing operations and current service potential. CWIP at original cost should be included in the current cost of property, plant and equipment, net of accumulated depreciation at year end if AFUDC and total interest charges are included in the determination of income from continuing operations.

I suspect that my remarks have led you to conclude that I oppose reporting the effect of changing prices in financial reports of utilities. Actually I favor reporting the effects of inflation on the equity investors. However data must be presented as supplementary information and determined in a manner that fairly presents the purchasing power of the equity capital retained in the business. This type of disclosure emphasizes the need to establish utility revenues at a level providing a return on equity investment sufficient to maintain the purchasing power of the equity capital and provide a real return to the equity investor sufficient to attract required capital in the future. Disclosure that does not properly reflect the economics of regulation could cause a higher risk factor to be attributed to investment in utilities by overstating the impact of inflation on the equity investor.

FINANCIAL REPORTING WITH PRICE LEVEL CHANGES

William J. Johnson, CPA
Controller
El Paso Electric Company

It is a pleasure to be here today and I appreciate the opportunity to discuss the Statement of Financial Accounting Standards No. 33 with you.

The objectives of Statement 33 are stated as being intended to help users of financial reports by providing assessments of future cash flows, enterprise performance, the erosion of operating capability, and the erosion of general purchasing power as measured by the effects of changing prices.

FASB 33 seeks to quantify inflation by measuring and disclosing its effects in financial reports. The reasons for such disclosure are listed as:

(a) The effects depend on transactions and circumstances of an enterprise and users do not have detailed information about those factors.

(b) Effective financial discussion can take place only in an environment in which there is an understanding by the general public of the problems caused by changing prices. That understanding is unlikely to develop until business performance is discussed in terms of measures that allow for the impact of changing prices.

(c) Statements by business managers about the problems caused by changing prices will not have credibility until specific quantitative information is published about those problems.

The question now is whether or not we have accomplished the objectives of Statement 33 from the utility standpoint. I cannot believe that an adequate answer can be derived at this time. The statement itself is an experimentation in the type of disclosure and provides for continued review of the information disclosed. However, let's see what conclusions can be drawn at this time.

Many utilities are involved in construction programs which require substantial sums from the capital markets. We must issue long-term debt, preferred stock and common stock. The issuance of these securities requires the disclosure of, in some type of supporting document, all material factors affecting the Company's operations. I believe that utilities are presently providing adequate information on transactions and activities of the utility through these documents.

The other panel members have discussed reporting requirements of FASB 33. As members of the general public, I wonder how many of you feel that you have an understanding of the problems on inflation from reviewing the information provided by these requirements. The general public does need to be made aware of inflation's effects on our respective companies, but we may have just added more complexity to an already complicated set of financial statements.

The statement is looking for a quantitative measurement of inflation. The customers of most utilities have felt the effects of inflation through fuel adjustment clauses for some time. This is a very quantitative measurement. In each rate case inflationary effects are represented through cost of service adjustments and cost of capital requirements. They must be quantitatively identified or they are not allowed. FASB 33 does reemphasize the problems faced by the utilities as a result of inflationary pressures and there is merit to the objectives contained in the statement.

The value of Statement 33 is still in question. An article in the April 1980 issue of Dun's Review summarized how analysts had viewed the information presented. Constant dollar results did not seem to help much. The article states that "most analysts believe that only the dividend information is really useful. From the adjusted results investors can see if the company's dividends have been keeping pace, declining or growing faster than the general rate of inflation." This does not seem to me to be a very significant achievement since this is a very simple calculation.

The article goes on to say that the current cost information is much more useful to the analysts. Their interest lies primarily in a company's ability to pay future dividends from earnings when the assets must be replaced. Utilities are not guaranteed an adequate return, but as assets are replaced or added, they are generally allowed to recover the cost of the assets and earn a return on the investment. This provides some measure of security to the investors, thereby reducing the value of current cost information as a good measure of dividend paying capability.

Many utilities face cash flow problems which could possibly impair their ability to meet their financial obligations. However, an analysis of the company's present financial statements and supporting information should provide a good indication of existing problems.

In conclusion, I believe that the information provided by Statement 33 may be useful for most industries, but is limited for utilities. I think it will take some time to refine and improve its understandability for use by the general public. However, I do feel that it can provide valuable information relative to utilities if we all work toward modifications to better present its effects.

UTILITY INDUSTRY RESPONSE TO FASB 33

Joe A. Jones
Supervising Manager
National Regulated Business Group
Deloitte Haskins & Sells
Washington, D.C.

You have just heard an outline of the basic requirements of FASB 33 and what the Statement itself requires to be disclosed in a company's financial statements or elsewhere in its annual report. I would now like to review with you the results of what a number of public utilities have actually done in responding to the requirements of FASB 33. To do this, I have reviewed a number of 1979 annual reports to shareholders in conjunction with the recommendations for responding to FASB 33 as established by the Edison Electric Institute's Accounting Task Force on Inflation Accounting. This Task Force meet in Dallas on October 31, 1979 and approved a number of specific recommendations which it established for compliance with FASB 33. I have also reviewed 43 annual reports to shareholders. 39 of these 43 are included in the top fifty public utilities in the United States.

My overall assessment of the responses to the Statement is as follows:

. Encouraging but a lot of "let's wait and see what everyone else does".

. A generally positive attitude towards the statement as opposed to the attitude of previous ASR 190 disclosures.

Specific breakdowns by numbers of companies in relation to the EEI recommendations are as follows:

A. Include current cost data in the annual report to replace the replacement cost data required by SEC Release ASR 190:

Included current cost data 33
Did <u>not</u> include current cost data 10

B. Use format as shown in Schedule B (page 33) of SFAS No. 33 as opposed to the reconciliation format:

"Schedule B" format 39
Reconciliation format 4

C. Treat inventory as a monetary item, i.e., adjust only for depreciation (and nuclear fuel where applicable):

Did 43
Adjusted for deprec. <u>and</u> other items 0

D. Used Handy-Whitman index for current cost information or did not disclose a specific index for current cost:

Did 32
Did <u>not</u> disclose index 1
Did <u>not</u> disclose current cost data 10

E. Note disclosure (narrative portion) recommended by the EEI:

Generally followed 33
Generally did not follow 10

F. Writedown to net recoverable value not included in income from continuing operations (i.e., disclosed "down below" with disclosure of monetary gains and losses):

Disclosed as described above 43
Continuing operations 0

G. Treatment of preferred stock in relation to determination of net monetary gains:

Appears from note to have treated at least some preferred stock as debt 13
Cannot tell from note disclosure the exact treatment of preferred stock 29
Treated preferred stock as non-monetary 1

Also, the FASB itself issued in December 1979 an illustration booklet showing a number of examples of FASB 33 disclosures. One section of this book contains such disclosures for the public utility industry. A review of the 43 annual reports in relation to the public utility disclosures illustrated in that booklet are as follows:

A. Five-year summary shown in average 1979 dollars:

1979 dollars	43
Some other year used as a basis	0*

B. Disclosure of net income or income from continuing operations adjusted by reduction to net recoverable value:

Made the adjustment	33
Did not show income as adjusted	10

* One company did show certain of the data using 1975 dollars as well as 1979 dollars.

THIRTEENTH SESSION, Thursday, May 22 - 10:15 p.m.

Concurrent Session F-2

DOUBLE-LEVERAGE FALLACY

CHAIRMAN: Richard Walker

SPEAKER: John L. O'Donnell, Ph.D., Professor
College of Business
Michigan State University

AN EVALUATION OF DOUBLE-LEVERAGE

John L. O'Donnell, Ph.D., Professor
College of Business
Michigan State University

DOUBLE LEVERAGE

Various definitions
The basic problem bothering its advocates
Historical origins and experience

REGULATION AND RATES OF RETURN

Book rates vs. market rates
Opportunity cost concept
Fair rate of return

MARKET RATES OF RETURN

Market rates govern allocation of investible funds
Investors are risk averse and rational
The riskless rate
Risk premiums
Source of funds does not determine RRR

ASPECTS OF RISK

Business risk
Operating risk
Financial risk
Interest rate risk
Purchasing power risk
The CML

FINANCING VS. INVESTMENT DECISION

Investment decision determines total risk
EBIT is the total fund
Financing divides total risk between suppliers of funds

THE CAPITAL BUDGETING DECISION

Single asset returns and risk
Portfolio returns
The WACC as a hurdle rate
A holding company as a portfolio of assets

INFIRMITIES OF DOUBLE LEVERAGE

Modern financial theory and practice emphasize nine major deficiencies

AN EVALUATION OF DOUBLE LEVERAGE

1. DOUBLE LEVERAGE THEORY
2. EFFECT OF DOUBLE LEVERAGE ON EQUITY RETURN
3. RATE OF RETURN
4. REQUIRED RETURN AND RISK
5. FINANCIAL LEVERAGE AND RRR
6. SINGLE ASSET VS. PORTFOLIO RRR
7. SINGLE VS. MULTIPLE RATES AND RISK
8. INFIRMITIES OF DOUBLE LEVERAGE

DOUBLE LEVERAGE THEORY

PARENT

		Debt	$200
		Equity	200
Total assets	$400	Total claims	$400

50 percent debt-to-total assets

SUBSIDIARY

		Debt	$150
		Equity	50
Total Assets	$200	Total claims	$200

75 percent debt-to-total assets

HYPOTHETICAL CAPITAL STRUCTURE

The $50 equity in the subsidiary is 100 percent owned by the parent. Therefore, the subsidiary's equity is really 50 percent financed by debt.

		Debt	$175
		Equity	25
Total assets	$200	Total claims	$200

RATE OF RETURN

1. BOOK RATE

2. MARKET RATE

3. OPPORTUNITY COST

4. FAIR RATE OF RETURN = WHAT UTILITY SHOULD BE ALLOWED TO EARN ON ITS INVESTED CAPITAL.

5. BLUEFIELD WATER 1923 AND HOPE NATURAL GAS 1944 ESTABLISHED THREE STANDARDS FOR FAIR RATE OF RETURN:

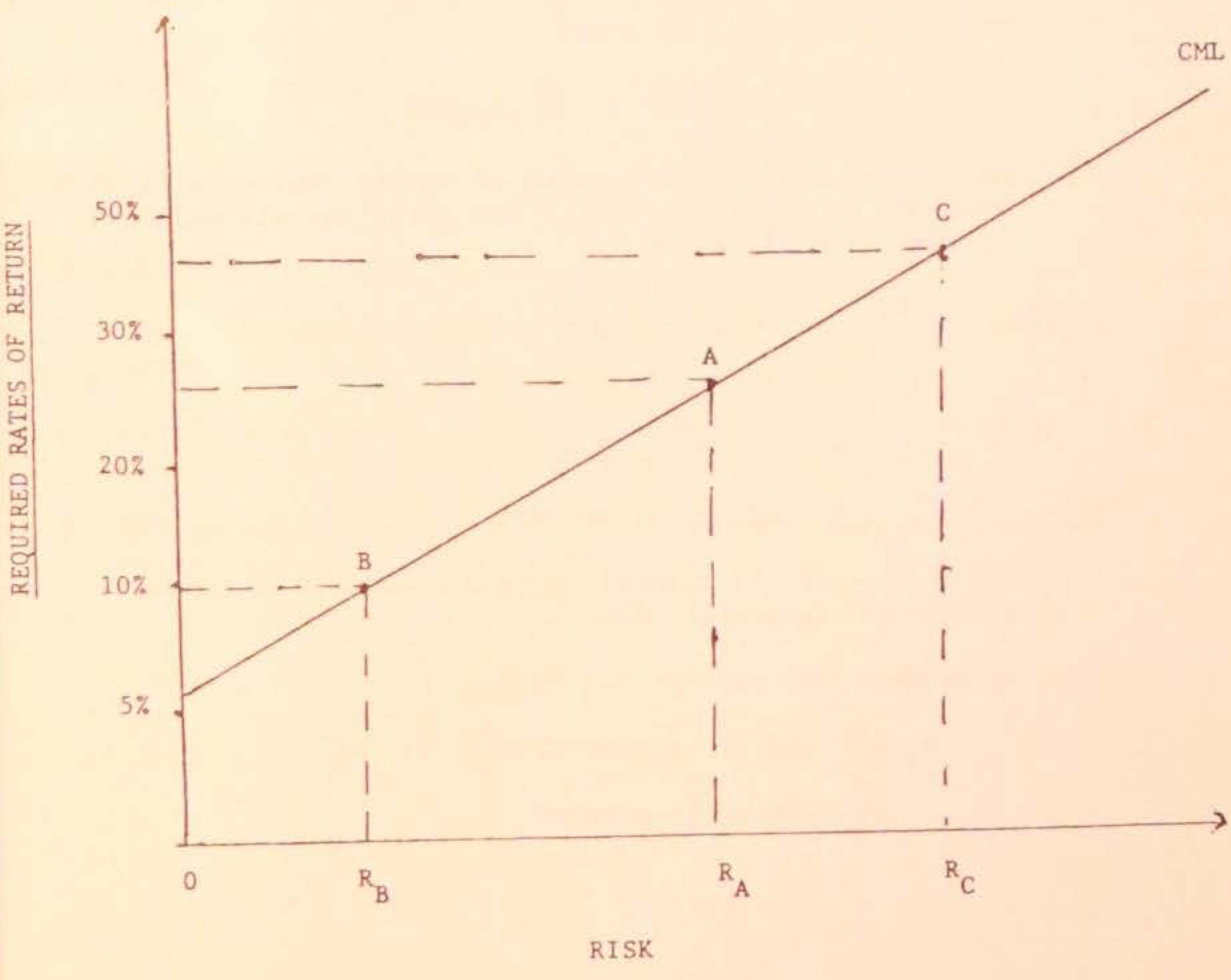
   (A) FINANCIAL INTEGRITY TEST

   (B) CAPITAL ATTRACTION TEST

   (C) COMPARABLE EARNINGS TEST

6. D.C. TRANSIT 1968. COMMISSION NEED NOT FIND COMPANIES WITH RISKS IDENTICAL TO UTILITY. CAN LOOK AT FIRMS WITH DISSIMILAR RISKS AND MAKE APPROPRIATE ADJUSTMENTS.

REQUIRED RATES AND RISK



FINANCIAL LEVERAGE AND RRR

GIVEN:

R_e = Market yield on common equity

S = Market value of common equity

B = Market value of debt

V = (B+S) = Market value of the firm

EBIT = Earnings before interest and taxes

A. An all equity investment yielding a RRR of 15 percent on operating assets. No taxes.

$$\frac{EBIT}{S} = 15 \text{ percent} \qquad 1.$$

B. Management retires 50 percent of equity replacing it with $500,000 of 8 percent debt. The total overall weighted average rate of return is:

$$.15 = .08\,\frac{B}{V} + R_e\,\frac{S}{V} \qquad 2.$$

$$R_e = .15 + (.15 - .08)\,\frac{B}{S} \qquad 3.$$

$$= .15 + (.15 - .08)\ 1$$

$$= \underline{.22} \text{ or } 22 \text{ percent}$$

The (.22 - .15) 7 percent premium needed to compensate equity for financial risk.

C. Introducing 48 percent tax rate

$$R_e = .15 + \left[.15 - (.08)\right]\ 1(1-.48) \qquad 4.$$

$$= .19 \text{ or } 19 \text{ percent}$$

SINGLE ASSET VS. PORTFOLIO RRR

ASSET	RRR
A	.15
B	.20
C	.30

ASSUME

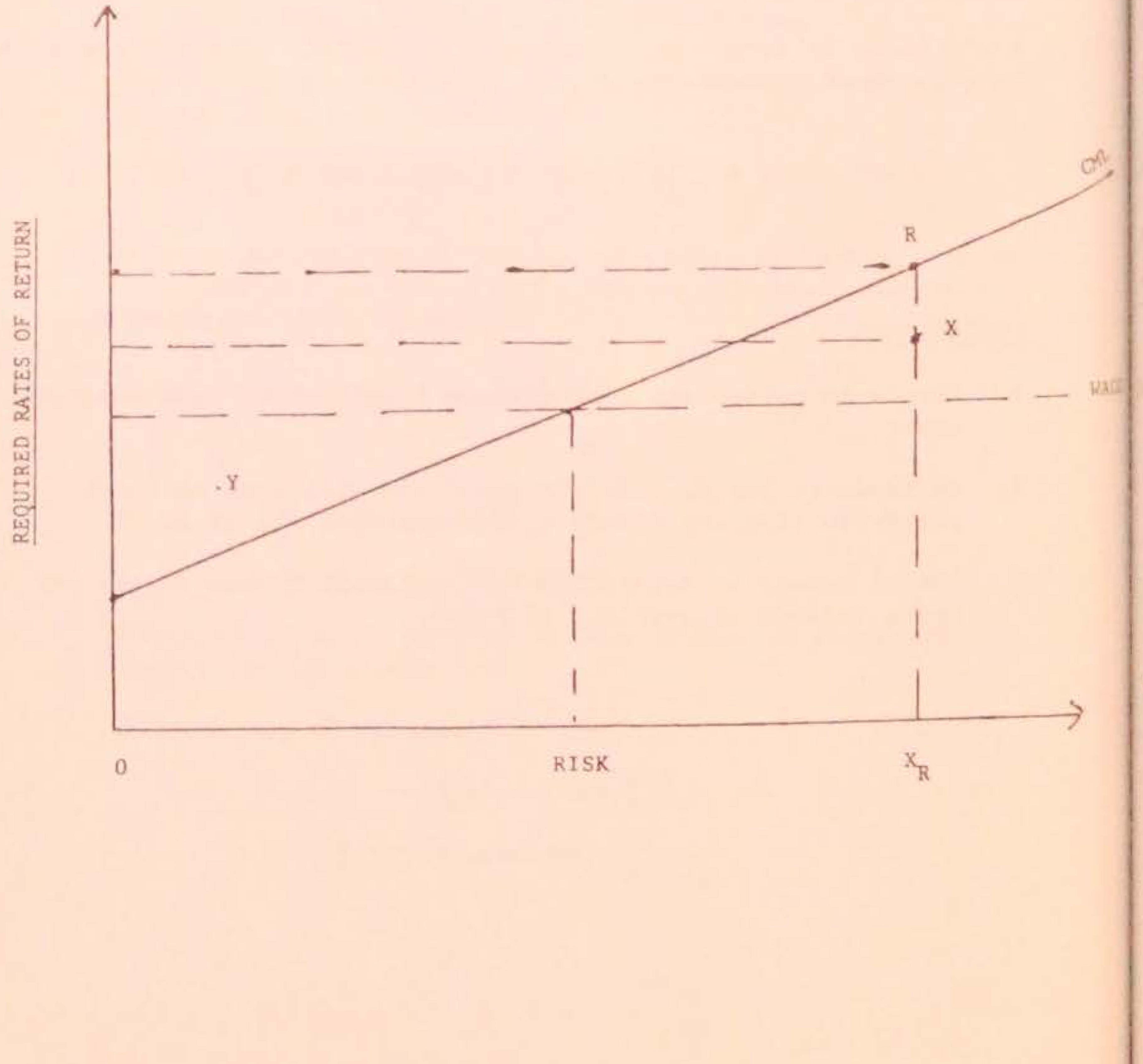
A portfolio is formed by investing a percentage of total resources in each asset as follows:

$$(.30)\ (.15) + (.30)\ (.20) + (.40)\ (.30) = \underline{.225} \text{ or } 22.5\%$$

CONCLUSIONS

1. Portfolio return and risk differs from that of each separate asset.
2. An investor buying into the portfolio will look at total portfolio risk and demand a corresponding RRR of 22.5%
3. RRR on assets is determined by impersonal market forces not by an individual supplier of funds.

SINGLE VERSUS MULTIPLE RATES AND RISK



INFIRMITIES OF DOUBLE LEVERAGE

1. Provides no allowance for differential risks between parent and subsidiary.

2. Implies that methods of financing permit tracing individual investment dollars from source to uses.

3. Implies that the source of funds determine the RRR on projects into which those funds are invested.

4. Creates an unrealistic hypothetical capital structure for the subsidiary.

5. Fails to recognize risk implications of the hypothetical capital structure and resulting impact on RRR for debt and equity.

6. Fails to acknowledge that debt floated a subsidiary is not a liability of the parent.

7. Fails to recognize that financial leverage involves risk commensurate with the degree of leverage involved. These risks are reflected in market RRR.

8. Double leverage is devoid of any defensible theoretical foundation. It is simply a mechanical arithmetic exercise which arbitrarily reduces the weighted average required rate of return for a subsidiary.

9. If applied, the double leverage approach guarantees that subsidaries will receive less than the RRR as determined in impersonal competitive capital markets. This result has serious adverse social implications.

FOURTEENTH SESSION, Thursday, May 22 - 10:15 p.m.

Concurrent Session F-3

DEPRECIATION AND LIFE ANALYSIS FOR THE 80'S

CHAIRMAN: J. C. Hempstead
Professor of Industrial Engineering (Retired)
Iowa State University

SPEAKERS: W. C. Fitch, Ph.D.

Charles H. McCarthy
Director-Depreciation
American Telephone and Telegraph Company

In general, the implementation of the capital recovery process (depreciation) will consist of identifying the amount of capital to be recovered, specifying the basis for allocating the capital to expense, determining the associated costs related to the efficient disposal of the capital residue (net salvage), and the timely recognition of the value of such residue in the process. The amount is a valuation-accounting concern; the allocation is an engineering-operation-accounting concern; the costs related to the disposal of the residual capital are an operating-accounting concern. This paper will address only the life estimation associated with the engineering-accounting aspects of the allocation process.

From another viewpoint, a discussion of life analysis might be related to its use in rate making, general accounting-corporate income and cost determination, valuation, ad valorem tax, income tax, and capital budgeting. This paper will concern itself only with the use of life and the estimation of life that relates to rate making and corporate accounting. As of 1980 both Generally Accepted Accounting Principles and the rules for including capital recovery in cost of service are in flux, i.e., see FASB-33 and contrast FCC, New York, Pennsylvania, and California treatment of depreciation. Thus it appears appropriate to examine how we got to where we are before we venture into the future.

HISTORY

A history of depreciation can be found in a number of places.[1] Recognition of capital consumption occurred centuries ago. The word depreciation has been used in corporate accounting for over a century; one of the earliest is included in an annual repo t of the Reading Railroad in 1835. Recognition of inflation in depreciation occurred in the early 1900's. U.S. Steel set forth the impact of inflation in its annual reports following World War II. Prior to 1930 the articles appearing in accounting, economics, and engineering journals, and in court and commission orders, contained wide ranging viewpoints about the use of life in estimating depreciation. In the period 1930 - 1947, many of the rules, regulations, definitions and most of the related research which are stillthe basis for regulation and accounting, were conceived and somewhat cast in bronze. Even though they have been revised, the essence of the 1930 versions is still there. Compare the following with current works:

> "Uniform Systems of Accounts," (ICC 1931, FCC 1935, FPC 1936)
>
> Life Analysis: Winfrey, "Statistical Analysis of Industrial Property Retirements," (Iowa State College, 1935)

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[1]A.C. Littleton, Accounting Evolution to 1900 (New York, American Institute Publishing Co., 1933)

Perry Mason, "Illustrations of the Early Treatment of Depreciation," Accounting Review, 1933. 8:209-218.

NARUC, "Report of the Committee on Depreciation" (1943 and 1963)
Bughan, Simulated Plant-Record Method (1947)

The studies, rules, and regulations which were made in the period 1930 - 1940 were reflections of the times; following an era of growth of population the growth was expected to decrease and level off at about 155 to 175 million by the 1980's. During this period, many prices fell or rose only slightly, detailed record keeping for plant and equipment was confined to a few companies, and computations were manual and laborious -- calculators were hand driven. The debates about divergent valuations in court cases were deemed to indict anything which was based on judgment. Likewise, those statistics of that era concentrated on description, not decision making. Life was thought of as related to a unit, wherein it could have a single value; probability, confidence, and error were seldom mentioned. Grouping of property was done to facilitate computation.

ERA OF FORMULATION OF RULES

Accounting Rules and Procedures. Accounting rules and procedures were developed in the 30's and 40's to offset the excesses of manipulation associated with the 1920's, minimize extensive analysis of hard to get data and, of necessity, short cut any process which required extensive calculations. Survival in the depression and war years was more important than precision or sophistication. Thus, methods were developed and applied with little or no concern about the long range effect. Just get the job done. As a result, we confused dollars with capital, descriptive statistics with a statistic used as a process parameter, and forgot that the use of empirical methods and estimates must be restricted to cases which are congruent with those cases from which the empiricism was developed.

Research and Interest in Life Estimation. Interest in, and study of, life estimation waned from 1950 onward with the exception of studies made at Iowa State, by the AGA-EEI Depreciation Committee, and by the AT&T who have continued to be foremost in their study and advocacy of good depreciation practices, including life estimation. A revival of interest in depreciation and life analysis began with the inception of the Iowa State Regulatory Conference in 1962, and the offering of the Depreciation Programs at Michigan Tech in 1967. A large number of papers related to all aspects of depreciation have appeared in the proceedings of these Iowa State conferences. A bibliography of these is included as an appendix to this paper. In 1967, the first of a series of educational programs was offered by Michigan Tech, transferred to Western Michigan University, and is now being continued by Depreciation Programs, Inc. As a result of the work at Iowa State University and Western Michigan University, there has been considerable research and discussion carried on to implement and improve the conferences and the programs as offered today. As a result, over six thousand participants from commissions and utilities, various levels of management, and the related professions, have been presented with the opportunity to appreciate better the complexity of the capital recovery process and the need for top corporate management to be involved.

ADVANCE IN LIFE ANALYSES IN THE EIGHTIES

The first advance in life analysis in the 80's should be a thorough examination of three distinct cases in which life estimates are commonly used: the single unit, the vintage group, and the open-ended account or continuous group. A study of the congruent use of averages developed from life estimation with their use in depreciation calculations should proceed concurrently. The first wave of understanding of depreciation began centuries ago with the focus on a unit. The second wave began to be apparent in the mid 1800's when accounting for larger companies began to group units for ease of depreciation calculations. The second wave of understanding of the life of property as a vintage group, rather than as a unit, has progressed such that a large majority of the people working with group property depreciation understand survivor curves and average service life procedure as they relate to a vintage group. The third wave of understanding, which concerns the relation of a vintage to the open-ended account, has just begun. Likewise, the understanding of the use of an average as displayed in descriptive statistics is apparently understood by a large majority of people, but its use as an operator is frequently misunderstood. A few examples may explain the current dilemma which arises in using averages which are good descriptors but which are poor operators.

UNIT DEPRECIATION: CONFIDENCE IN LIFE ESTIMATE

In most instances, average life of a group has been explained in terms of a vintage group and has been used inappropriately with open-ended accounts. Let us briefly review three cases using simple arithmetic examples to see what should be considered.

CASE 1 A UNIT - you have only one cab in your company. You are to estimate the life of that cab. That cab is similar to those in a group of 1600 cabs which have been studied. From that study we judge that an applicable series of probabilities that any cab will be retired at successive ages is as follows: 0-1:0%, 1-2:16%, 2-3:22%, 3-4:24%, 4-5:22%, 5-6:16%. The average is three years.

Confidence in the Estimate of Life of a Unit. Under today's approach, the life of the unit would generally be estimated as three years. With this estimate you would be right 24% of the time; 32% of the time you would be low by one or two years and 32% high by one or two years, Fig. 1. What happens to your return of and return on when your unit has an actual life of two years and you use three? If the unit cost $10,000, you obviously would have a return[2] of only 2/3 of the cost. Where would the 1/3 come from?

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2 Revenue requirements are assumed to be based on current cost of service using a three year life, and these revenues are assumed to be realized.

Current income? Retained earnings? If you had a 20% return on net book, you would have earned $3,333 and you would lack $3,333 which would have been your depreciation expense for use of the non-existent capital the third year. Obviously there would be no revenue for the third year. If the return were less than 20% of net book, your total funds available would be inadequate to continue business. This unfortunate situation could occur because:

> Today we would accept the three year estimate as proper, using the rationale that if your actual life is less than that estimated, you will have other property with an actual life over by a comparable amount. In this instance, since you only have one unit, there is no offset.

Because most rates of return do not include overt recognition of a need for a risk component to serve as a quasi-insurance that capital will be recovered, it is reasonable to assume that it is overlooked by less informed management and most investors. If risk is included and its component part of the rate of return is not identified, it is difficult to compare the amount of the risk that capital will not be recovered inherent in the life estimate with risk provided for in the rate of return. Rates of return for utilities have been arrived at by studying the rates of returns for reasonably comparable nonutility companies, wherein the corporate depreciation practices for setting the accrual rates are governed by different attitudes on synthesizing the cost of capital.

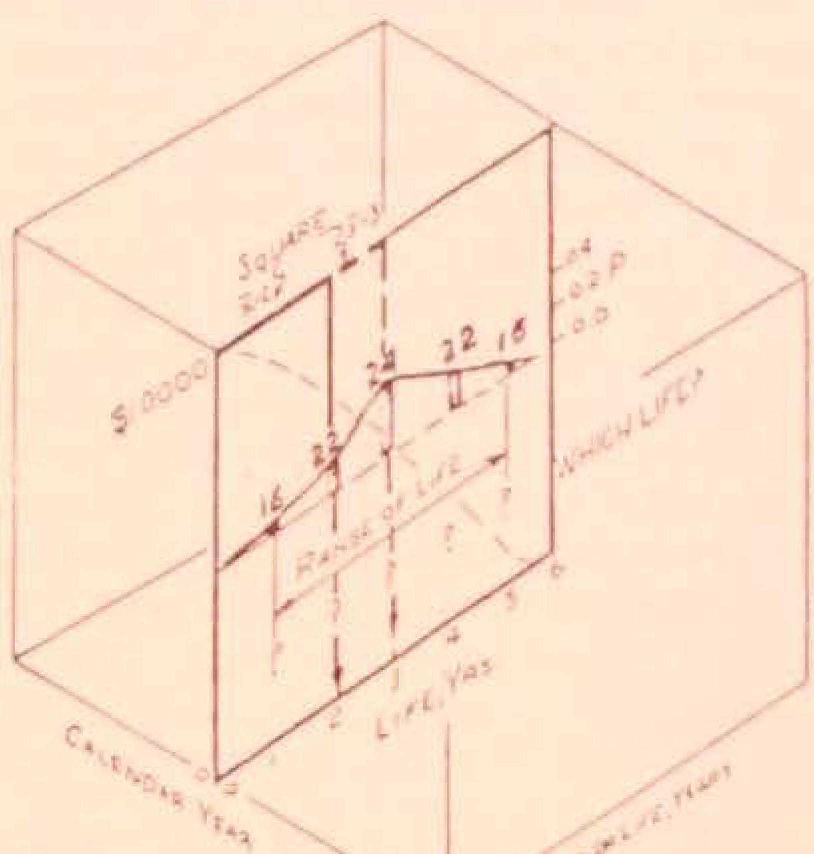

Fig. 1. Frequency of retirement of units used in estimating life of an individual unit

Risk of Not Recovering Capital. Generally, depreciation accrual rates for nonutility property are somewhat higher than for utility property because of several factors: 1. Freedom to set rates within less restrictive, generally accepted accounting principles, 2. Federal income tax analogy, 3. Revenues independent of depreciation practices, and 4. The need to replace obsolete plants to remain competitive. With higher accrual rates for nonutility properties than for utility properties, the risk of fully recovering capital in nonutility property should be less than the risk of recovery of capital in utility property using the current accrual rates based on today's approach to establishing accrual rates for public utility property. Thus when nonutility rates of return are used as a basis for establishing the rate of return for utilities, the imputed risk component associated with capital recovery implies that the same certainty of capital recovery occurs in utilities as in nonutilities. Such an implication is to be questioned. Likewise when the cost of capital is synthesized, the omission of an overt element of risk results in the same conclusion.

If a risk component is contained in the rate of return, which is doubtful because few if any depreciation analysts have been asked about the risk in their estimate, funds developed from the risk component should be used to offset the capital which is not recovered. Such compartmentalization of return appears to be unworkable. Thus, greater confidence in the life estimate should be sought.

Confidence in Life Estimate of a Unit. If capital recovery is reasonably certain for the nonutility companies, then the life estimates of necessity would be such that you would expect to be right a large percent of the time.[3] In Case 1, if two years is used as the life estimate, 16% of the time you would anticipate a risk of not recovering capital. Again, unless there is adequate recognition of the risk that capital will not be recovered as a component of the rate of return, the life estimates in the 80's should recognize this by evaluating the various alternative possible life estimates in terms of probability of success. Choose that estimate which will provide the confidence or non-confidence limit which agrees with that risk of not recovering capital used in establishing the rate of return. To simplify calculations, all retirements are assumed to occur at mid year.

VINTAGE DEPRECIATION

CASE 2 A VINTAGE GROUP - You have purchased 100 identical cabs in one year. Data is supplied to you from various cab companies concerning the aged history of 100 cabs in each of 100 vintages. There is no indication of the calendar year for each vintage. The data were obtained

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3 The judgment of percent right or wrong is a serious decision to be made by those with authority to take such risk. 84% and 16% are arbitrarily chosen and are not intended to be guides.

by a card survey similar to Case 1 in which you requested that the life history of 100 cabs purchased in any one year be displayed and returned to you. The retirements are reported with the mean, standard deviation, and skewness. From this information you are to estimate the survivor curve and average life to use with the 1980 fleet of cabs you have just purchased.

Estimate of Survivor Curve. In Case 2, the problem is to estimate the survivor curve to be used with the cabs purchased in 1980. A corollary would be to estimate the future portion of vintage curves of cabs purchased in years prior to 1980. We might proceed by studying the survivor curves for each of the groups. When the survivor curve is plotted for each of the groups, we would find not one survivor curve shape but several curves varying about a mean survivor curve. This is comparable to finding the variation of the lives of units about a mean life in Case 1 example pertaining to one unit.

Confidence in the Estimate of Survivor Curve. In Case 2, however, we have need to study this variation in life in three dimensions such that the varying curvatures of the survivor curves can be displayed. Statistically, these could be described by the frequency of the means of several survivor curves, of the standard deviations, and of the skewnesses. Rather than proceed through the statistical calculations which are required to compare each of these cases, it will suffice to plot them on a single chart with percent surviving as the Y axis and age as the X axis. As in Case 1, we could now plot the means as a frequency curve, the O, L, S, and R type curves as frequency curves, and the number of the height of the mode of the curves as frequency curves. In this way, the variety of curves from which we should choose the one which we judge to be most appropriate for cabs purchased in 1980 can be displayed.

If the analogy with Case 1 is used, it is reasonable to assume in Case 2 that we will have some survivor curves with lesser means dispersions and skewnesses than the average and others which have larger means dispersions and skewnesses. A sketch of a survivor curve representing the aggregate of all 100 curves is shown in Fig. 2.

Thus, as in Case 1, it is incumbent upon us to recognize that the risk inherent in estimation of an average survivor curve is such that we can afford the risk should our estimate be wrong 16% of the time. In Case 2, as in Case 1, several comparable items, i.e., vintage curves, have been examined. This set of survivor curves varies about a mean survivor curve which resulted from averaging all the curves used. As in Case 1, this set of survivor curves is described by counting the number of means, standard deviations, and skewnesses of various values. No recognition is given to vintage year with which any mean is associated, similarly, for the standard deviation and skewness. In summary, only the number of survivor curves having a particular mean or a particular shape without regard to the chronology of occurrence is available. As in Case 1, the number of units having a particular life, standard deviation, or skewness, were counted. No trend is shown because the vintages are not identified.

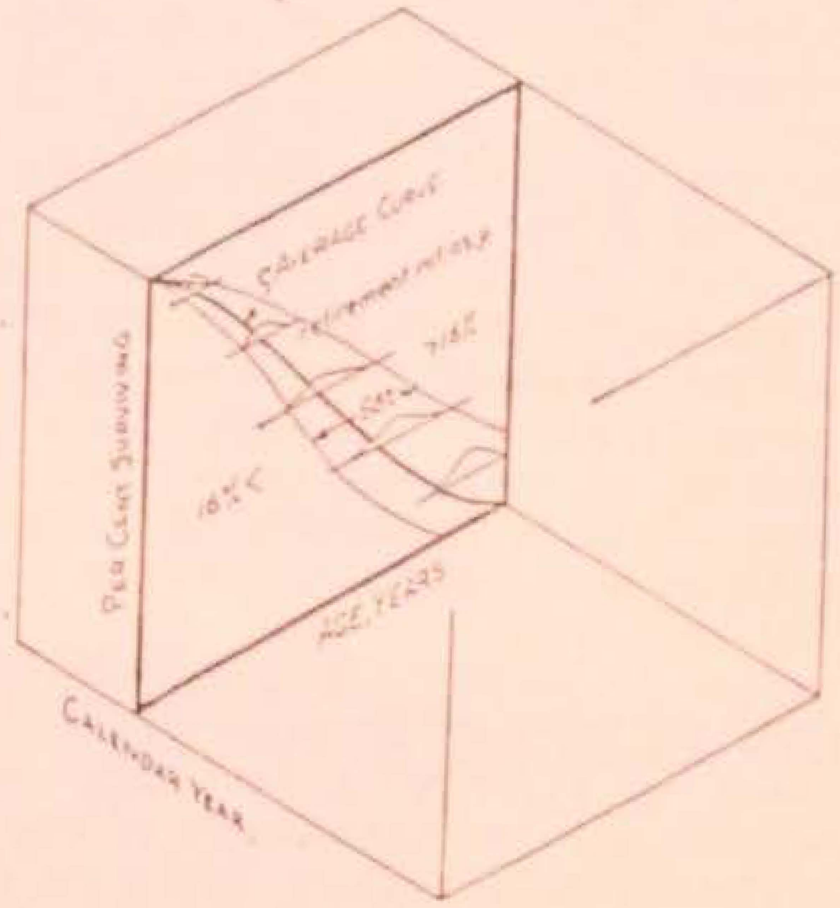

Fig. 2. Frequency of retirement ratios and resultant survivor curves within ± one σ

OPEN ENDED ACCOUNT

CASE 3 In Case 3 you are managing a cab company. You have historical information about your company for the past 50 years. You also have available to you the historical experience of other cab companies for a similar period of time. You have available to you several opinions about what will happen to the economy, to the city which you serve, to the use of cabs, and plans for public transportation. You are to estimate the future survivor curve for each of the surviving vintages, and the curve which will be applicable to the cabs which you will buy in 1980.

The generally accepted approach to making this estimate is to develop a series of survivor curves for bands of years using the retirement rate method. An average survivor curve resulting from a study of the bands of years is selected; frequently the average curve used is the direct result of fitting a chosen band. When a specific band is used two things should be recognized: 1. The calculations underlying the band give no recognition to the trend of retirement ratios, and 2. The average survivor curve will probably approximate the survivor curve applicable at the mid year of the band.

Frequency of Life Parameters. A word about frequency distributions. The frequency distribution is a count of the number of events as they apply to units, vintages, and open-ended accounts which occur in a defined interval. In the usual life analysis this is the number of, or percent of, the total retirements which occur during each age interval. (See Fig. 1)

Frequency of Life from experience of 1600 units (Case 1)

	Age Interval					
	$0-\frac{1}{2}$	$\frac{1}{2}-1\frac{1}{2}$	$1\frac{1}{2}-2\frac{1}{2}$	$2\frac{1}{2}-3\frac{1}{2}$	$3\frac{1}{2}-4\frac{1}{2}$	$4\frac{1}{2}-5\frac{1}{2}$
No.	0	256	352	384	352	256
%	0	16	22	24	22	16
p	0	0.16	0.22	0.24	0.22	0.16

In Case 2 the information to be displayed consists of three life characteristics of a group: $\bar{x}$, σ, and ψ or for Iowa Curves average life, height of mode - number and type. A similar set of frequencies as those in Case 1 with additional frequencies of type and modal number are:

Frequency of the Average Life of the 100 Survivor Curves (Case 2)

	Interval of Average Life, Years					
	0-1	1-2	2-3	3-4	4-5	5-6
No.	0	16	38	30	14	2
%	0	16	38	30	14	2
p	0	0.16	0.38	0.30	0.14	0.02

Frequency of the Height of Mode[4] of the 100 Survivor Curves

	Modal Numbers						
	0	1	2	3	4	5	6
No.	5	12	14	42	23	3	1
%	5	12	14	42	23	3	1
p	0.05	0.12	0.14	0.42	0.23	0.03	0.01

[4] A better classification would result by first classifying the Type-Mode No. of Iowa Curves according to σ's. See Carr-Hall Effect of Retirement Dispersion Patterns upon Age-Life Depreciation Calculations, Unpublished Manuscript, 1947.

Frequency of the Type Curve
of the 100 Survivor Curves

	Type Curve			
	0	L	S	R
No.	4	18	30	48
%	4	18	30	48
p	0.04	0.18	0.30	0.48

The frequency of the type curve and modal number could be tabulated in a combined tabulation of Type and Mode: 0_4, 0_3, 0_2, 0_1, L_0, L_1, L_2, ... R_4, R_5. However, there is considerable similarity between some of these combinations, making the categorization more difficult.

This set of three frequency curves does not reveal trends in the parameters. Thus if any trend exists, the probability that is developed empirically from studying the 100 curves likely will not be applicable to 1980 vintage.

Time as an Added Dimension. The added variable in Case 3 is the time series trend of the various elements of the life characteristic (mean, standard deviation, skewness). A sketch of such a series of survivor curves is shown in Fig. 3. For each characteristic there could be several trends of the same time series about the mean of the various time series. The trend could be a linear, curvilinear, or step curve. For the three trends there could be various linear, various curvilinear, or various step curve trends. Thus, for each of the latter three trend shapes there are also frequency distributions which relate to the shape. In making the estimate of the survivor curve selected for use with the property installed in 1980, various outputs available from a computer analysis of the past data, when integrated with other factors, will produce the large array of choices of survivor curves which should be narrowed down, first through an analysis of the stubs which have been developed, and second with respect to the alternative interpretation of the subjective information with respect to its impact on the forces of retirement beyond that which is contained in the analysis of historical data.

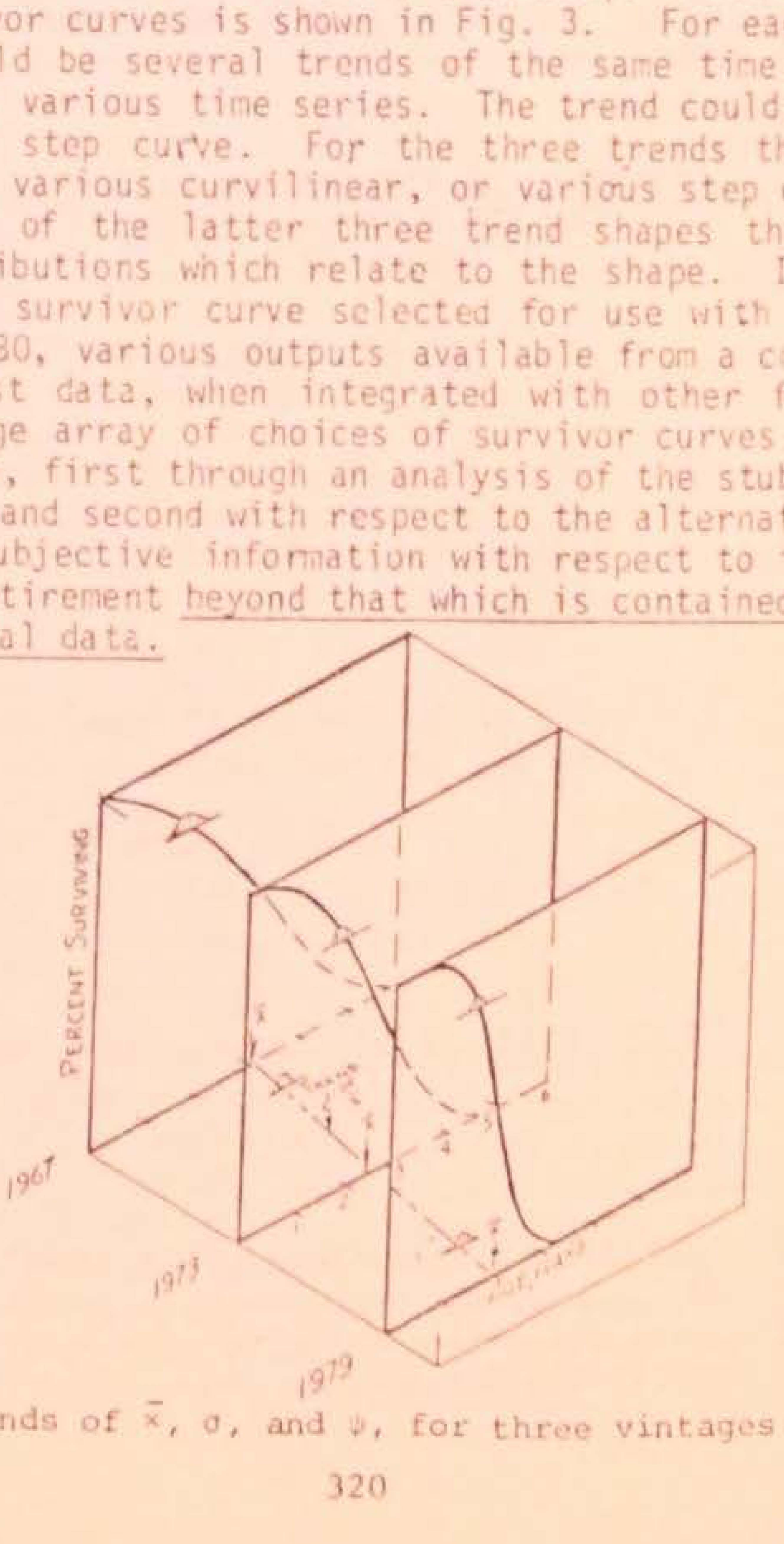

Fig. 3.

Time series of trends of $\bar{x}$, σ, and ψ, for three vintages in an open-ended account

One element of the analysis of the past history might be to termine the most important parameter which is changing with time d examine the trend of that parameter in recent calendar years. ch a trend would assist in estimating the parameter applicable to e property in 1980. For example, to estimate the shape of the rvivor curve which is indicated by past history, the retirement tios could be estimated for each age interval using the trend of tirement ratios over recent years and select those retirement tios for each age interval which would give a proper confidence vel. Note that the estimate for the first retirement ratio for e 0 to ½ would only be for one year hence, for 4½ to 5½ would be ur years hence, and therefore applicable to 1980 property in 1984 d correspondingly more distant for subsequent ages. Again, the timate would be such that there is a confidence level of 84% or pect non-recovery of our total capital no more than 16% of the me. Fig. 4 is from a previous study of the boundaries of a nfidence level in an actual account. It indicates the increasing vergence of the possible survivor curves using 68% confidence vel meaning 68% of the possible curves lie between the outer ots. With such need for understanding and billions of dollars plant affected, only well qualified professional staff assisting concerned management can be expected to provide assurance of the pital recovery necessary for maintaining a healthy business.

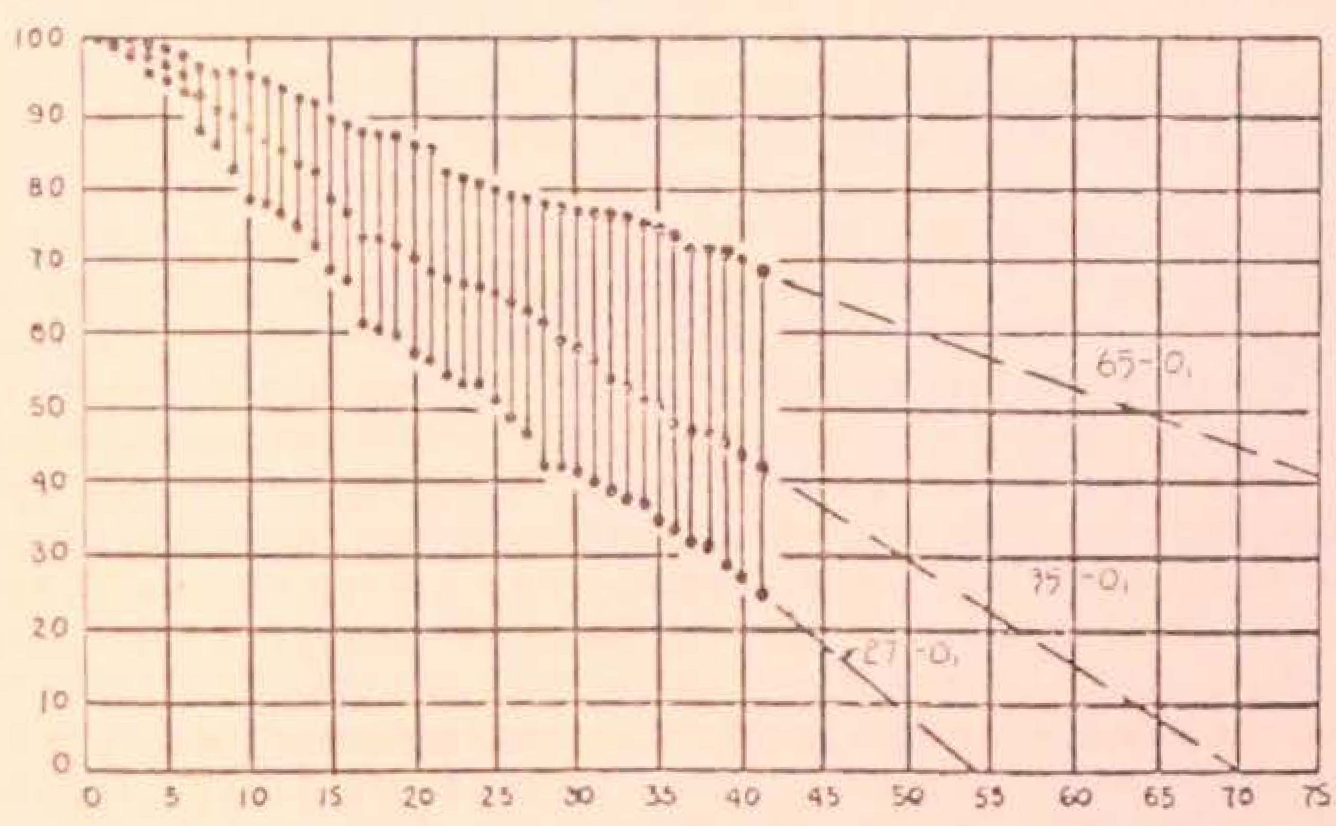

Fig. 4. Approximate region for 68 per cent of possible survivor curves

Assumptions to Simplify Study. With all of this complexity it is no wonder that assumptions have been made which will allow us to factor out some of the complex functions that are a part of our mathematical models. If for the open-ended account in Case 3 we assume that survivor curves for all vintages are the same, the shape of the survivor curve can be factored out and its variation with time ignored. Thus, a single curve can represent all vintages in the total group of property. When an average survivor curve is used for an account, a constant survivor curve is implicitly assumed. If we assume the shape of that survivor curve to be square, we can then factor out from all vintage groups all concern about dispersion and return to Case 1 where a unit is either in service or retired and only a single life used.

In a similar manner we can remove the problem of associating a confidence level with the unforeseen termination of the many vintages in service in a property similar to Case 3 by the factoring out process. We can remove the problem of how much of the investment represented by the tail end of the survivor curve will be unrecovered by factoring out the shape. After these two simplifications we now have the situation where either the unit is in service or not in service. In this simplification, it is easy to see what the confidence level or error refers only to -- the probability that the unit will live or not live at least "z" percent of the time within ± "m" percent error. Each of these assumptions introduces an approximation the degree of which sould be assessed before accepting it.

VARIANCE IN LIFE ESTIMATION

Having set forth the idea of the variance associated with each of the cases, we can now recognize that a fourth dimension of life analysis to be researched in the 80's is variance. Coupled with this is the confidence or non-confidence and error or tolerance associated with each estimate of life. Although there have been numerous systems with computer programs developed for the calculations required in life analysis, and more advanced systems which have been programmed and made available to assist in the estimation of depreciation, they do not include an analysis of variance.

When variance is considered, the challenge of life estimation to the professional is even greater than before these systems were available. The complexity of analysis and synthesis associated with the recognition and understanding of the significance of the variance of a large number of parameters describing the shape of the historical curve is compounded by similar variations in the future. To assess the variance of the unknown aspects of the future requires the professional to become more knowledgeable about the whole of a company's operations rather than concentrating on massaging data. Becoming thoroughly aware of where a company and an industry are going in the long term future is a key element in forecasting future life.

The recognition of the problems of interpreting a historical erage when coupled with an examination of the appropriate average use should discourage the use of concepts that rely upon and ud the use of answers read from computer outputs and/or broad erages in capital recovery calculations. In addition, there are veral ways of calculating an average life depending upon the use be made of it. Attention should be given to determining the erage life which conforms to the depreciation method and procere used. Use of the wrong method of averaging lives can contribe to an under-recovery of capital in time when lives are creasing.

TURE LIFE AND OBSOLESCENCE

To eliminate the concern about variance in the estimate of the st when calculating depreciation, emphasis should be placed on e estimation of the future portion of the stub survivor curves of der vintages, not on the extension of the overall average curve the past. Actual stub curves, when extended using the curve t BY JUDGEMENT represents a reasonable estimate of the future, ovide the most information possible about the survivor charactertic of a property group. When making such estimates of the ture, recognizing the trends and variance of trends, the impact current operations, technology, regulations, and management cisions and plans on the future life of extant property is emphased more so than when we are encumbered with compositing several st and future curves. This should relieve many concerns of agement about the <u>extent</u> to which current and anticipated obsolcence is included in estimates, rather than whether obsolecance included in estimates. Economic factors including obsolescence ays have been included in actuarial and simulated analyses to extent that they were a force in the past. The recognition of trend and its variance should cause professionals to question ther or not the current forces, which can be expected to continue, plus anticipated other forces, are given appropriate weight the estimate of future life. This brings us to another aspect life estimation that should be adopted in the 1980's. The disction between realized life and future life.

As the past is known and life has been realized, information lost by using an average curve to represent the past when estiing life and calculating depreciation. Data from the past will w us to depict the realized life which has occurred and concente on forecasting the future life. Currently there are many a bases which began between 1940 and 1950 and provide history over 90% of the current plant in service. For those vintages r to the current data base, an appropriate approximation can be on the basis of the best available information and fixed so these past data, once approximated, will not be revised each a new study is made as happens when a different survivor curve sed because a new band has been selected on which to base the age curve.

Realized Life vs Forecasting. To determine the realized life we need not use a smooth survivor curve. In fact, using a smooth survivor curve decreases the amount of information available because we have eliminated the exact information and substituted an average. Each vintage can be evaluated separately and any unusual early retirements which should be a part of the average life of the plant included regardless of the cause. Exclusion of such is undoubtedly wrong in that it will deny the company the chance to include in accrual rates the shorter lives of the unusual retirements. Unusual retirements may, and probably should, be removed from consideration when analyzing data for the purpose of forecasting. Survivor curves used for calculations related to the average service life and used to test for accumulated depreciation should not be confused with the survivor curves used for forecasting. The analyses which seek to ferret out the trends in life characteristics of property require data from which the unusual has been removed to facilitate forecasting.

The discussion in this paper provides a logic which may be pursued to show that it is not only desirable but necessary to calculate depreciation for each vintage (or use the equivalent composite rate) rather than treat all vintages as a single group. The explanations which have been made in recent texts about calculating depreciation for group property are acceptable for a vintage but not for an open-ended account because the explanation applies to a different well bounded population which differs from the ill defined population in an open-ended account.

In the vintage calculations, it is easy to isolate realized life from future life. Furthermore, the population to which the average applies can be defined with reference to a specific investment. This is not so with an open-ended account as the group continues to change with each successive year. In Case 3 the estimation of the future life for the 1980 vintage was discussed; in addition, it is generally necessary to estimate the future life of other vintages. A review of the discussion of the open-ended account in Case 3 will reveal that additional considerations should be given when estimating the future life of older vintages because the future life is conditional upon what has happened to a vintage prior to the study.

USE OF AVERAGES

To progress further in our exploration of life analyses in the 80's, a few simple examples will illustrate the care with which the results from analyses should be examined to be certain that a particular kind of average is appropriate for use with a given depreciation process. Caution should be exercised not to use a descriptive statistic, ie., average life, as a parameter in a depreciation process equation unless the average is computed appropriately.

In Case 1 a survivor curve could be developed from information about the 1600 cabs. From that curve an average life of the 1600 cabs could be calculated and an average life of the one cab estimated. In the process of estimating depreciation on a single unit, the survivor curve for the 1600 cabs does not apply to one unit, rather a square survivor curve is appropriate. In Case 2, an average survivor curve from a recent band of years should not be used for 1980 unless the curve shape remains nearly constant for all vintages because the curve is not applicable to a specific vintage. In Case 3 the average life from a direct weighted average curve should not be used when there is a trend in life because depreciation calculated using that average will not allocate the total cost, neither more nor less, even when the average is precisely calculated and even if it is ultimately realized. Nor should we use the average curve shape for testing the level of accumulated depreciation when there is a trend in type and modal number.

What average[5] should be used as a parameter in the depreciation process calculation? First, define or bound the investment population in a (property) group for which the average is to be used, for example, the vintage. Once the population is defined, it is essential that the rate derived from the average life be used from beginning to end of the life of the group in order to fully allocate the cost. When one vintage is combined with another subsequent vintage which has a different life, we will violate the basic principle of total allocation if we adopt the new average without an adjustment because we created a new group, i.e., two vintages instead of one and the average of the two cannot be used from beginning to end. The new average cannot be used for the first year(s) of the open-ended account because that year(s) for the first vintage is in the past.

AVERAGE LIFE FOR OPEN-ENDED ACCOUNT

A simple example using an open-ended group consisting of two vintages of two units each depreciated, using the straight-line depreciation method and the average life procedure, will illustrate the hiatus.

> Two vintages, 1960 and 1963, each consisted of two \$1,000 units. The 1960 vintage consisted of one unit with a five year life and a second unit with a fifteen year life. The 1963 vintage consisted of one unit with a four year life and one unit with an eight year life.

Fig. 5a illustrates the survivor curves for the two vintages and the calculation of the average life shown for each. As more than one vintage is portrayed a third dimension is needed to represent calendar years. The third dimension is shown below the step curves and the curves are offset. A different kind of survivor

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5 The kind of average is determined by the method of calculation and weighting, i.e., harmonic, geometric, unweighted, dollar weighted, or unit weighted. What kind you calculate depends upon its use.

curve for the two vintages is obtained by plotting the surviving balances for each as shown in Fig. 6.

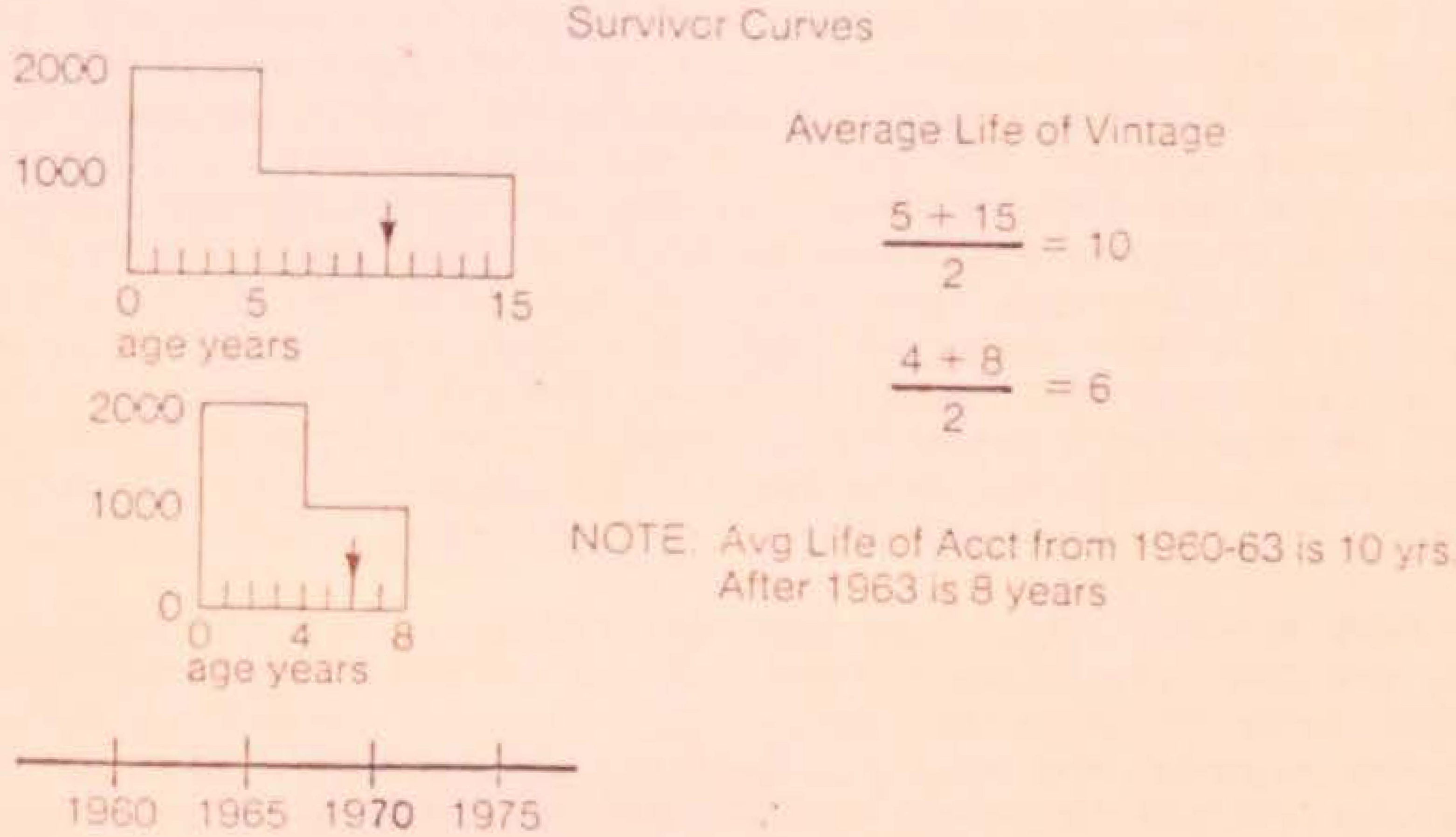

Fig. 5a. Illustration of beginning of open-ended account with two vintages

1960 - 62 Average Life 10 years Rate 10%
1963 - 75 Average Life 8 years Rate = 12½%

DATE	ASSET		ACC Depreciation		NET
1/1/60	2000				
1/1/61				200	200
1/1/62				200	400
1/1/63	2000			200	600
1/1/64				500	1100
1/1/65		1000	1000	500	600
1/1/66				375	975
1/1/67		1000	1000	375	350
1/1/68				250	600
1/1/69				250	850
1/1/70				250	1150
1/1/71		1000	1000	250	350
1/1/72				125	475
1/1/73				125	600
1/1/74				125	725
1/1/75		1000	1000	125	850
					(150)

Fig. 5b. Open-ended account

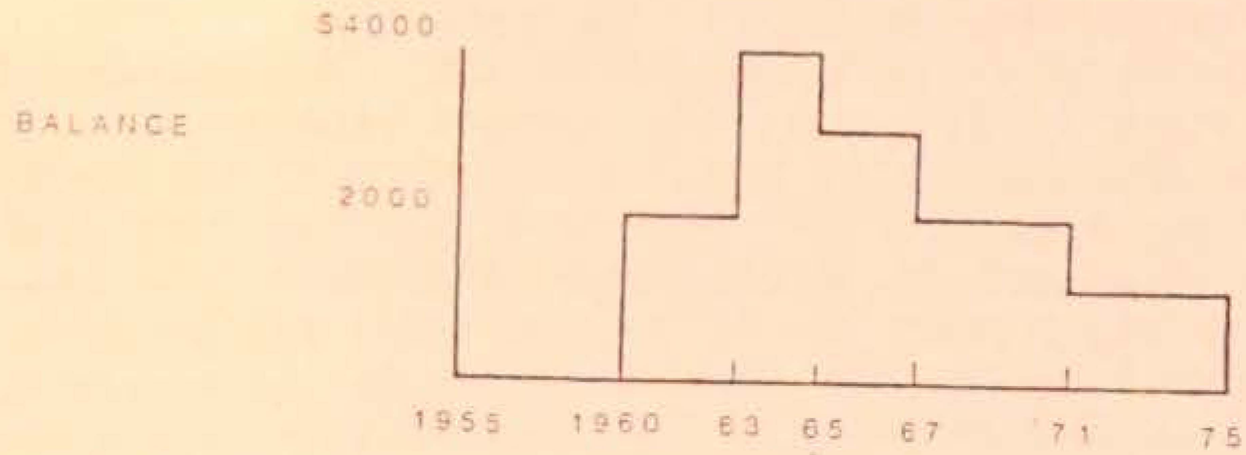

Fig. 6. Surviving balance in account - Case 2

If these two vintages are combined into a common survivor
ırve, as would generally be done in an actuarial or SPR life
ıalysis, a four-step curve would result, as illustrated in Fig. 7.
rom this curve an average life of the two vintages of eight years
ın be calculated, but the shape applies to neither vintage. Thus,
ıformation was lost when the two curves were combined. The result
f using a dollar weighted average life to determine the accrual
ıte for an open-ended account with varying lives is illustrated in
ıe table in Fig. 5b.

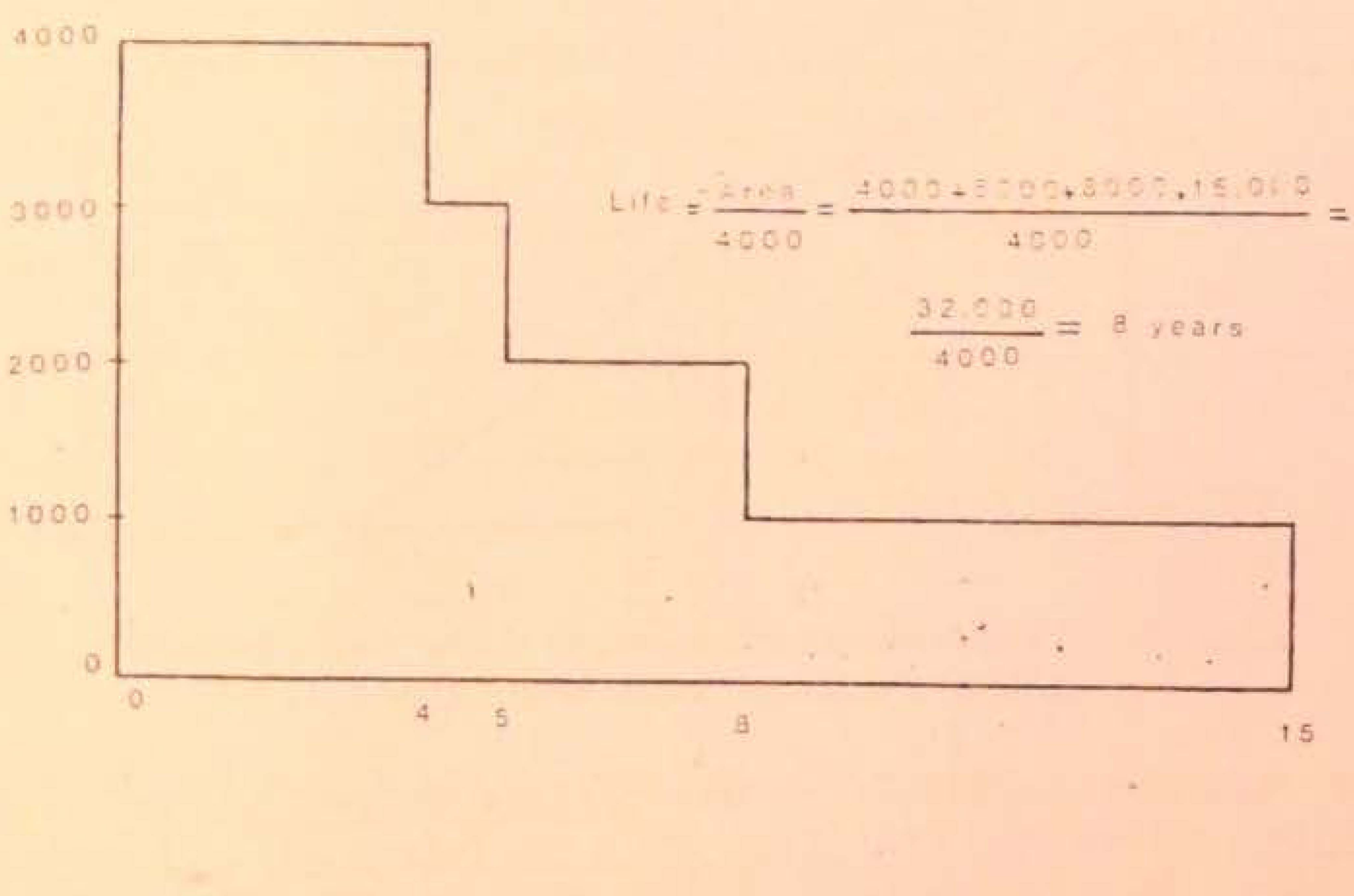

Fig. 7. Composite original group of two vintages - Case 2

Fig. 5b shows the debits and credits in a T-account for the four units and two vintages. The retirements are debited as depicted by the survivor curves in Fig. 5a. The average life of the first vintage is 10 years; the accrual rate is 10%. It is used until the 1963 vintage is installed after which the average life of the open-ended account is eight years and the rate 12½%. As the group is redefined in 1963 to consist of both 1960 and 1963 vintages, the eight years should be used until the group is gone. If 10% is used from 1960 to 1963, and 12½% to the surviving balances from 1963 to 1975 as shown in Fig. 5b, the entries are shown in the column headed ACC Depreciation. The total of accruals is $150 less than the sum of the debits for the four $1,000 retirements. This deficit of $150 is caused by changing the population and the recalculated average being used as a process parameter when it could not be used for determining all accruals for the property group througnout its entire history.

When depreciation was calculated in 1960 the population consisted of only vintage 1960. Three years later the population was a combination of 1960 and 1963. Because the 1963 vintage was not included with the 1960 vintage before the 1963 investment was made, the three accruals for 1960, 1961, and 1962 at 12½% were missed (10% was used), amounting to $50/year which, when included for three years, would offset the negative $150 shown at the bottom of the column. Thus, the use of a dollar weighted average for two successive vintages where the life differs is incorrect. The apparent problem is to associate the average and population to obtain the appropriate composite accrual rates.

Fig. 8. Calculation of average life for vintage using realized life and future life

The solution is simple -- use vintage accounting and vintage calculations based on realized life plus future life of each vintage or ELG. An illustration of the realized and future portions of a survivor curve is shown in Fig. 8. Although the discussion of estimating the future life in this paper relates to the straight-line method with the average life procedure, and the above solution suggests that discussion relates only to vintage accounting, it also relates to estimating future life when the equal life group (unit summation) procedure is used.

If the composite rates are calculated for each year and the intage method is used, the composite rates are calculated as ollows:

Vintage year	1960-1962	1963-1970	1971-1974
		Average Life	
1960	10	10	10
1963		6	
		Vintage Accrual Rate	
1960	0.10	0.10	0.10
1963		0.167	
Sum	0.10	0.267	0.10
Sum/ Number of Vintages	0.10	0.133	0.10
Composite Rate, %	10.0	13.3	10.0

If the population were defined as successive groups in each calendar year such that each unit was a "group" with separate lives, the groups would be as follows:

Years		1960-62	1963-64	1964-65	1966-71	1971-74
Number of Units		2 Units	4 Units	3 Units	2 Units	1 Unit
Lives, n, of units		5,15	4,5,8,15	4,8,15	8,15	15
1/n:	1/4		0.25	0.25		
	1/5	0.20	0.20			
	1/8		0.125	0.125	0.125	
	1/15	0.067	0.067	0.067	0.067	0.067
Sum		0.267	0.672	0.442	0.192	0.067
Sum/ Number of units		0.133	0.168	0.146	0.096	0.067
ELG Rate, %		13.3	16.8	14.6	9.6	6.7

This grouping is equivalent to that used in the unit summation process which is also known as the equal life group, ELG, procedure. Other rates could be calculated depending on the disposition of the $150 difference. Based upon the three calculations of composite rate shown, the following comparison results:

	1960-62	1963-64	1964-65	1966-70	1971-74
Usual	10%	12.5%	12.5%	12.5%	12.5%
Vintage	10%	13.3%	13.3%	13.3%	10%
ELG	13.3%	16.8%	14.6%	9.6%	6.7%

THE AVERAGE SURVIVOR CURVE

In contrast to the survivor curve for one vintage which is a plot of the property surviving in the continuing property records for that vintage from date of installation to present, the survivor curve resulting from an experience band which is developed by chaining ratios does not represent history. It has a different meaning. What population or group of property does a one-year experience band represent?[6]

To review, the survivor curve developed for a one-year experience band results from the chaining of successive retirement ratios[7] based on the number of units retired during any age interval divided by the number of units surviving at the beginning of the age interval. In the case of the one year band for 1979, it would be the ratio of the property retired during 1979 from each vintage divided by the survivors as of January 1, 1979 for each vintage. Such a survivor curve is a picture of a hypothetical group which would be composed of property having retirement ratios for each interval equal to those calculated for the year 1979. No such group exists. When the life estimate using this curve is used to develop a rate to be applied to an open-ended account, it would imply that these probability ratios were applicable to the oldest vintage as well as the most recent.

6

There are many more questions which we could examine by similar means. The most important question concerns the averaging process: does the kind of analysis -- actuarial, composite original group, turnover, or SPR -- provide an average which is weighted in the same manner that is assumed in the development of the depreciation process model?

7

Retirement ratios when used in this way are conditional probabilities.

When the width of the experience band is expanded to 12 years nly data in the records during those years is used even though roperty surviving in 1967-1979 may have been purchased from 1929 o 1966. The history for the vintages prior to 1967 is not used nd may not be available. Thus, the survivor curve from the experence band, 1967-1979, can not represent the factual history of the lder vintages. Rather, the curve for the 12-year band represents hypothetical group of property which would have the same conitional probabilities as the retirement ratios which are the uotient of the sum of the 12 years of retirements during each age nterval divided by the sum of the surviving property at the beginin of the year of each age interval. The use of these ratios to onstruct a survivor curve both approximates the past and sets orth the future using these conditional probabilities -- an unikely possibility.

For a vintage such as 1940, the average survivor curve from he 1967-1979 band would impute history for the vintage from 1940 o 1967 and forecast future life from 1979 until the last unit is etired from the 1940 vintage. If a trend exists, this curve is nlikely to be the same as the actual one for 1940. Similarly for ny other vintage.

When can such an average curve be used in the calculation of epreciation? Only when there is no trend, and the variations are andom about the mean curve, will the calculation of accrual rate nd the accumulated ratios be reasonable.

IDTH OF BAND

The question is not how wide a band you use, but how you use uccessive bands and trends of the various parameters to assist in stimating the future. This is not a static process but a dynamic ne which requires the considered judgment of a team of profesionals. The extent to which a team is involved depends upon the mportance which management company or commission attaches to ssuring a reasonable chance for full capital recovery.

CONCLUSION

In conclusion, the life analyses in the 1980's will extend nderstanding of the impact of using an open-ended account or ontinuous property group as the depreciable group in several ways. he analyses will focus on methods of determining trends in all imensions affecting service life. The following list comprises hose areas.

1. A distinction will be made between the estimation of life and life characteristics appropriate for a single vintage and that which is appropriate for an open-ended account.

2. Realized life and future life will be distinguished between in the process of life estimation.

3. The parameter which varies in each of the cases, unit, vintage, and open-ended accounting, will be identified, and variability of this parameter, or probability that it will have given values, recognized in life estimation. The question of how often you wish to be right and how often you can afford to risk being wrong will be addressed.

4. A definition of the population of property described by the survivor curve which has been developed by one of the various life analysis methods, i.e., actuarial, SPR, or others, will be investigated.

5. Until vintage calculations are adopted, average life calculated from dollar or percent weighted averages will be adjusted downward or upward, depending upon the trend of life, to compensate for the bias of direct weighting when inverse weighting should be used.

6. When ELG is used, appropriate recognition of future life vs realized life will be made.

7. Judgment will be recognized as a major factor in life estimation.

Most important, we will balance the risk that the rates based on an estimate of life will not recover capital during the period of the estimated life whether overall average, vintage average, or ELG composite average with the risk component in the rate of return on that capital. Many other aspects of the capital recovery process, in depreciation in particular, undoubtedly need our attention. The systems to implement the use of forecasts of future life and the use of vintage calculations are readily available.[9]

A demonstraton of the life analysis system currently in use was given by Mr. E. C. Hostettler, Chief of the Depreciation Branch of the Interstate Commerce Commission. Mr. Hostettler was assisted by Mr. Don Harrison of the Interactive Sciences Corporation. The system is interactive and used on line by the Commission. A data base of all accounting for Road and Equipment assets is maintained by the ICC. Analyses which support the developments suggested in the paper are available within this system, which can be obtained by writing to Mr. Hostettler.

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9 ICC, Users Documentation for the Computer Assisted Depreciation and Life Analysis Systems. Washington, DC 1979. (Write to E. C. Hostettler, Director, Depreciation Branch, Bureau of Accounts, Room 6C11, Interstate Commerce Commission, 12th & Constitution Ave. N.W., Washington, DC 20423.

DEPRECIATION PAPERS
Presented at
THE IOWA STATE REGULATORY CONFERENCE

by Subject
1962-1979

DEPRECIATION

Date	Author	Title
1962	A. R. Colbert	Depreciation Policy for Public Utilities
1962	C. N. Ostergren	Depreciation -- A Few Unsolved Problems
1964	Robert Smith	Economic Penalty of Early Property Retirement
1965	Walter J. Cavagnaro	Depreciation Estimates
1965	W. C. Fitch	Depreciation Estimates - Goals, Policies, Methods
1967	Richard Walker	Depreciation - Today and Tomorrow
1967	C. J. Schwingle	Depreciation and Obsolescence in the Non-utility Industry
1967	Evert E. Karlsson	Meeting the Obsolescence Problem in Depreciation
1967	Edward C. O'Rear	Depreciation - Today and Tomorrow
1967	Robert G. Warnek	Depreciation - Today and Tomorrow
1969	John F. Craig	Depreciation in Regulated Industries
1969	Charles W. Smith	Amortization of Investment in Hydroelectric Projects
1969	Ronald D. Jones	Depreciation and Ratemaking
1970	Clarence Unnevehr	The Engineering Economist, Accrued Depreciation, and Public Utility Just Compensation
1971	C. T. Loshing	Who is Responsible for Acequate Depreciation Rates?
1971	Henry E. Crampton	Who is Responsible for Adequate Depreciation Rates? An Engineering Viewpoint

Date	Author	Title
1971	Clayton L. Bullock	The Responsibility for Adequate Depreciation - An Independent Accountant's View
1972	John F. Craig	Focusing on Responsibility in Depreciation
1972	E. C. Hostettler	Responsibility for the Initiation of Depreciation Practices and the Implementation of Rates
1972	Robert G. Warnek	Technical Considerations in Depreciation
1974	Everett L. Morris	Capital Recovery and Internal Cash Flow
1974	B. W. Meythaler, Sr.	It is Now Time to Consider the "Last Cause" for Depreciation
1974	Frank K. Wolf	Depreciation in a Period of Rapid Economic Change
1976	W. C. Fitch	Feedback Control in the Capital Recovery Process
1978	Daniel L. Trampush	Capital Recovery
1978	Charles H. McCarthy	Impact of and Inclusion of Obsolescence in the Establishment of Depreciation Rates
1979	H. A. Offutt	Capital Recovery - Financial Concerns
1979	Arend J. Sandbulte	Depreciation - Who Cares?
1979	Alfred E. Ueberroth	State Commissions' Concerns About Depreciation
1979	Walter G. D'Haeseleer	State Commissions' Concerns About Depreciation
1979	Robert S. Bleackley and Aly Elfar	Development in Depreciation in the Telecommunications Industry in Canada

LIFE ANALYSIS

Date	Author	Title
1962	Robley Winfrey	The Development and Use of the Iowa Type Curves
1964	W. C. Fitch and William Shelbourne	Life Estimation
1966	Allen Henderson	The Weibull Distribution in Life Analysis
1968	George E. Lamp	Simulation of Retirement Ratios and Fitting Polynomials to Retirement Ratios
1968	R. E. White	How Dependable are Simulated Plant-Record Estimates?
1970	H. E. Crampton	The Uniform Format Used in the Bell System for Developing Average Service Life
1976	Robley Winfrey	Depreciation, Service Life, and Engineering Valuation in the Early Years at Iowa State University
1978	Karen H. Ponder	New Developments in Life Analysis (no paper available - see theses)
1978	John G. Russo	New Developments in Life Analysis (no paper available - see theses)
1979	Barnard H. Bissinger	What Really is Obsolete?

PROPERTY RECORDS

Date	Author	Title
1962	John D. Russell	Utility Property Records
1970	R. E. White	Modeling the Behavior of Property Records

SALVAGE

Date	Author	Title
1977	G. Robert Faust	There Ought to be a Law Against Negative Salvage
1977	Frank K. Wolf	Negative Salvage - Its Influence on Depreciation Expense
1977	Thomas S. LaGuardia	Recovery of Nuclear Power Plant Decommissioning Costs

VALUATION, PRICE LEVEL,
AND TRENDING

Date	Author	Title
1962	W. C. Fitch	Modern Engineering Valuation
1963	Ernest C. North	Trended Cost by General Indexes
1964	William A. Crabb	Depreciation Estimates For Current Cost of Plant
1964	Henry R. Crampton	Depreciation Estimates for Current Cost of Plant
1971	Jose Duarte Magalhaes	The Problem of Monetary Updating of Depreciation in Brazil
1973	C. W. Reid	Property Valuation in the Insurance Area
1973	Jack W. Newby	Valuation and Depreciation Re: Condemnation and Take-over of Public Utilities
1973	H. E. Crampton	Depreciation Aspects of the Reimbursement to Public Utilities for Plant Relocations Involved in Federal Aid Highways
1975	Jay H. Price, Jr.	Price Level Depreciation Revisited
1975	Robert O. Wagner	Why PLD? (Price Level Depreciation - What it is)
1975	Donald R. Hagerman	Price Level Depreciation Revisited

MISCELLANEOUS

Date	Author	Title
1967	Webster C. McEachern	NARUC Depreciation Manual
1967	Daniel McLean	NARUC Depreciation Manual
1976	Arend J. Sandbulte	Use of Survivor Curves in Economic Planning
1976	Roy H. Berglund	The Use of Iowa Survivor Curves in Income Tax Situations

Depreciation and Life Analysis for the 80's

Charles H. McCarthy*
Director-Depreciation
American Telephone and Telegraph Company

ntroduction

t is a pleasure for me to be here this morning, and I welcome the pportunity to present my views on depreciation.

he theme of the panel discussion, Depreciation and Life Analysis in he 80's, is timely, and I hope when I conclude my remarks, they will ave stimulated our thinking. I must indicate at the outset, however, hat if I knew the future and the shape of things to come, I would ndoubtedly be something other than a depreciation analyst. Recently, here has been increasing realization of the importance of depreciaion especially in public utilities. For the most part my remarks ill be focused on the telecommunications industry.

et us begin by going back almost a hundred years. In 1884, r. Thomas Sherwin, the Auditor of American Bell Telephone Company, ent to the Bell licensee companies an accounting circular which read, n part:

> "The telephone business has not been sufficiently long established to afford trustworthy statistics from which the average depreciation of plant and equipment can be determined. The usual estimate of such depreciation is ten percent yearly, taking all classes of plant together..."**

ell, 96 years have passed since the issue of that statement on depreiation in the telephone industry, and with all these years of experince and statistics behind us, it appears we have come full circle. rustworthy as they may be, historical statistics, when used in life nalysis, are no longer adequate as the principal guide in projecting he future lives of depreciable plant in the 80's. As in 1884, it eems again that we have insufficient information relative to the uture, and we must re-examine our depreciation and life analysis ethods.

hy is this re-examination necessary at this time? The presumption hat historical experience is a reasonable predictor of the future is ow questionable. As the caption of a recent FCC News Release states, e are at the dawn of a new era. This caption reads:

> FCC CHAIRMAN SAYS NEW ERA OF COMMON CARRIER REGULATIONS IS COMING, WITH OR WITHOUT COMMUNICATIONS ACT REWRITE.***

The views expressed in this paper are solely those of the author and do not necessarily reflect the view of AT&T or the Bell System.

** Subject-Accounts, a circular from the Auditor of the American Bell Telephone Company, Boston, April 25, 1884.

*** NEWS, Federal Communications Commission, Washington, D. C., March 24, 1980.

I believe this statement is not only applicable to all aspects of telecommunications, but is indicative of changes to regulated industries in general. What has led to the arrival of a new era in the 80's is the impact of far reaching changes in technology. This impact was only perceived in the fifties, became noticeable in the sixties, and became all pervasive in the seventies.

Until the seventies, the telephone depreciation analyst, like his colleagues in the gas and electric utilities, was concerned chiefly with one problem--how to apply trustworthy plant statistics in his life analysis and develop seemingly adequate depreciation rates.

As Figure 1 illustrates, the refinements during the past hundred years were made to improve the tools of life analysis and depreciation methods. Also during that period standard methods and formats of life analysis were developed, and generations of analysts were nurtured for whom graduation curves and projection life tables, realized life, proportion surviving, and future life expectancy were everyday terms. The application of high speed computers provided the depreciation analyst with a tool to streamline the laborious graduation studies. This, in turn, strengthened the sense of confidence in the existing methods of life analysis.

Paradoxically, the consequences of the very technological explosion that brought us high speed computing, among other things, have in the seventies jolted the depreciation analyst out of the seemingly secure and single-dimensional world of historical plant statistics.

Concurrent with these technological innovations, a multitude of regulatory issues arose. The resulting decisions created a process of change in the structural, regulatory and economic framework of the industry. Figure 2 lists some of the significant regulatory actions which contributed to this process of change. There is a probability that these actions will be followed by a changed Communications Act, formalizing the new era of communications.

Dimensions of Change

Any perspective, relevant to depreciation and life analysis in the 80's, has to include at least four dimensions of change. These dimensions are competition, nature of assets, financial environment, and depreciation methods. These may be characterized as the four M's: Marketplace, Merchandise, Money, and Methods.

Because these multiple dimensions will impact life analysis, the depreciation analyst's traditional role as a basic prober of past investment experience will, I believe, change increasingly into that of a participant involved and knowledgeable of investment planning of the future. As Mr. Charles Brown, Chairman of AT&T, has stated in the AT&T 1979 Annual Report: "..., it might be concluded that the Bell System's only certain prospect is change. Not since its beginnings has the future of this more than a century old business been less predictable than it is now--or more open to new possibilities."*

* American Telephone and Telegraph Company 1979 Annual Report, Page 3.

A. Marketplace

Prior to these decisions, regulated monopoly was generally taken for granted and life analysis was relatively simple in concept. Yesterday's mortality experience was viewed as a reasonably reliable guide and tomorrow's mortality was expected to result from causes similar to causes as in the past.

Today, as a result of decisions made by regulators and the courts (and in anticipation of probable Federal legislative action) the gates of at least two major communication submarkets are swinging wide open. In Washington, there is a consensus in the pending congressional bills amending the Communications Act of 1934 that the terminal market and the enhanced services market should be deregulated. This is obviously based on the view that the public interest can best be served by competitive forces stimulating innovation and the introduction of new products and services.

Let us look at some of the changes which have occurred in the marketplace. In 13 of the 100 largest United States cities, five or more Other Common Carrier's offer their intercity transmission services; in 20 more cities, three or more such carriers are in operation. As for equipment, when telephones and telephone answering devices are featured in the Sears Roebuck catalog--you know competition has become part of the American scene. This advent of competition, nurtured in a favorable regulatory climate, requires substantial changes in life projections. In a competitive environment, market obsolescence will play an increasingly greater part in the decisions concerning retirement of plant investment. With an increasing number of participants and a greater diversification of products, the higher the level of uncertainty is, relative to the innovations a competitor may have in his sales kit. Concurrently, in the customer equipment and enhanced service areas, deregulated rates will no longer necessarily achieve full capital recovery.

To ensure full capital recovery, new methodologies for life projection will become necessary. One such new methodology will likely employ marketeer's tools, such as life cycle analysis of individual products. New methodology will also require further disaggregation of investment data instead of grouping a large number of products into broad depreciation study categories. In developing the projected product investment life, greater reliance must be placed on inputs from the marketing and engineering disciplines.

Coupled with the increased diversity of products in a competitive environment is the increased risk of not achieving full capital recovery. The probable substitution of new products for products now in service will undoubtedly affect the marketability of existing products. The resulting market obsolescence and subsequent retirement will shorten the service lives of existing products.

Figure 3 demonstrates the life shortening trend of Bell System prescribed average service lives for PBX's during the period from 1957 through 1979. The decreasing life estimates during this period represent the best estimates made within the present framework of life analysis. These did not, however, give due weight to the future retirements caused by the introduction of new and diversified competitive products. The reliance on detailed analysis of historical data for life projections produces the illusion that appropriate consideration is being given to the rate of future retirements and life shortening effects. However, as shown here, these methods did quite poorly in anticipating the actual life shortening effects. Clearly new methods of life analysis are needed.

Customer terminal products are not the only type of assets affected by competition. Network facilities are also subject to life shortening, resulting from less than achievable utilization of facility capacity due to demand shift to competitors. This decrease in utilization may result in economic inefficiencies which, in turn, may lead to earlier than estimated retirements. The depreciation analyst must, in developing life estimates, anticipate the effect of competition on future demand for facilities.

B. Merchandise

Let us now turn to another dimension in which the 80's can be expected to bring rapid changes, the dimension that was termed merchandise. This represents the type of physical assets necessary to operate the business.

Telecommunication technology is clearly changing at an accelerating pace, and so is the role that technological obsolescence plays in reducing the life span of equipment and facilities. At times it is economic to take out of service equipment that physically is still perfectly serviceable. The savings in terms of cost, space, maintenance and ease of operation outweigh any hesitations attendant to early retirement.

Examples of rapidly changing technology are all around us. In a recent conference,* Federal Communications Commissioner Joseph Fogarty made mention of breakthroughs in transmission media, namely, communication satellites, coaxial cable and fiber optics. He also alluded to the application of computer technology to communication switching along with the introduction of the microprocessor to the communication terminal.

Advances in telecommunication switching and terminal technology are tied to the dramatic advances that have transformed computer systems. We have seen how in less than two decades a powerful computer installation has shrunk from the size of a barn to that of a suitcase or two. Obviously these developments have been and will be reflected not only in the "merchandise" of the future unregulated industry--such as in the PABX market--but will impact significantly the life characteristics of the switching machines, which are used in providing network services.

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* Federal Communications Commissioner, Joseph R. Fogarty, Remarks Before the Eleventh Annual Conference of the Institute of Public Utilities -- Michigan State University, Williamsburg, Virginia December 10, 1979.

Upon the introduction of the electronic switchers, they were initially assigned an average service life of 40 years, based on the estimated life span of their predecessors. As the electronic switchers were installed, provision for early retirement of the predecessor electro-mechanical switchers began to occupy a large share of the time spent on depreciation rate prescriptions. In the most recent three rate prescriptions for Bell Companies, the intial 40 year ESS life span has given way to agreed upon depreciation lives ranging from 26 to 29 years. While this is a significant reduction, in my view, it is a relatively modest change in view of technological advancements.

In the transmission area, a new technology which is rapidly developing into a factor of major importance, is fiber optics. Many years ago, the potential of light wave transmission with a capacity significantly greater than existing transmission systems was recognized. But it was not until the early 70's that the feasibility of optical fiber transmission was demonstrated on a laboratory scale.

While it is too early to estimate how fast fiber optics will replace existing technology, one can observe the exceedingly brief interval from lab demonstration to commercial application. It took 18 years from patent application for coax cable in 1929 to the first large scale commercial installation of coaxial cable in 1946. In the case of fiber optics this span has been less than a decade. This is indicative of the faster pace with which technology in the 80's might advance, and its resulting life shortening effects.

This means that the depreciation analyst must be concerned with the future technological advances which will impact the lives of existing assets. This indicates the need to continue to sharpen the tools of technological forecasting. The effect of technological changes can best be determined, in my view, by analyzing finer grained and functionally more homogeneous investment categories. This allows specific consideration of effects on asset lives which might be masked if a broad categorization were utilized. Finer grained investment categories are necessary to track the capital recovery of specific types of technology.

C. <u>Money</u>

Next, a perspective on depreciation in the 80's must also consider the impact of changing monetary values. No matter which viewpoint the depreciation analyst favors--that of the accountant concerned with the rational and systematic allocation of historical costs, that of the businessman viewing depreciation as an internal source of funds, or that of the economist concerned with measuring the decline of future income producing capacity--the recovery of investment posed few problems in periods of relative monetary stability. Provided the life estimates were not completely off the mark, the results were acceptable, regardless of depreciation viewpoint.

In the 1970's, however, the economy has experienced significant inflation. While inflation can be expected to abate from the current 18% rate, I suspect that the 80's will "enjoy" an average inflation rate of not less than 9%. Even at 9% per year, a dollar 10 years hence is comparable to 40 cents today. Combined with the volatility of market structure and the enormous needs of all industries, especially utilities, continued capital recovery based on historical dollars may not be the answer in the 80's.

The accounting profession's concern about the usefulness of accounting data in periods of inflation produced some gingerly attempts at designing accounting methods that took account of inflation. As you are aware, the recent Financial Accounting Standards Board Statement #33 has required supplemental statements of income and expenses. So far it appears these efforts have created more heat than light. Industry can expect to see significant practical results only if depreciation expense as reported on the primary statements is developed on some other basis than historical costs.

The financial welfare of the Bell System is closely tied to an adequate program of capital recovery--not only because it is a source of cash flow for construction but also because it is essential to the fiscal soundness of the business and to attract capital on sound terms. This concern becomes critical during periods of rapid inflation because of inflation's erosive effect upon the purchasing power of the capital recovery dollar. Appropriate timing of capital recovery is needed to reduce the impact of inflation.

As we enter the 80's we must keep in mind that asset life is an important but not the sole factor that should be recognized in the depreciation process. In this context, the economic value of an asset in terms of the future revenue producing capability is a valuable benchmark. If accumulated recovery is adequate, the unrecovered investment will be equal to or less than its economic value. This obviously requires an additional orientation towards the financial aspects of investment.

D. Methods

The final dimension of change relates to methods. The new environment of the 80's will require new depreciation methods, as well as new techniques of analysis. Depreciation analysts must first become aware of the need for change. They then must develop appropriate new methods, and must convince others of the need for the new methods.

The first of two key requirements of new methods is that full recovery of invested capital should be achieved. The straight-line vintage group method generally used today, does not ensure full recovery under changing conditions. This method is not responsive enough to compensate for the inevitable changes in life estimates. This has not been a relatively significant problem in the past since life estimates have been relatively stable over time and have changed only gradually. However, under conditions where changes may occur more frequently and be of greater magnitude, due to competition and changing technology, the straight-line vintage group procedure is not appropriate. This method does not assure full recovery of the capital investment because it assumes past accruals were appropriate and determines future accrual rate based on this assumption.

An important step, I believe, in adapting to conditions of the 80's, which would allow meeting the requirement for full recovery, is to implement the straight-line remaining life method of depreciation for embedded plant. The straight-line remaining life method can be viewed as a refinement to the currently used straight-line vintage group method. Like other straight-line methods, the straight-line remaining life method is designed to recover investors' capital over the expected service life of the vintage group on a straight line basis. Incorporated in the straight-line remaining life method is a positive tracking system to monitor accumulated depreciation, which permits the recovery of the undepreciated amount over its remaining life.

Under typical conditions, where life estimates are revised, the straight-line remaining life method, unlike the straight-line vintage group method, will adjust the timing of the recovery of the unrecovered investment to reflect the revised life estimate in such a manner as to ensure full capital recovery (no more, no less).

The second key requirement for capital recovery in the 80's is achieving timely recovery. That is, matching the timing of annual depreciation accruals with annual capital consumption. A refinement to the straight-line vintage group method with the objective of achieving more timely recovery, is the straight line equal life group method (unit summation method).

This method has been proposed by Bell as an appropriate method of matching capital recovery with straight-line capital consumption for new plant, since it provides the benefits of unit depreciation on a grouped basis. With a true-up or adjustment provision, the straight-line equal life group method ensures full and timely capital recovery.

The essential change required in life analysis techniques is to shift the focus from today's reliance on historical experience to reliance on adaptive forecasting and prediction. We must confront the unavoidable uncertainties involved in forecasting future events and estimating lives, and not be comforted by the apparent precision of the statistical graduation methods now used.

I am not suggesting that we discard the historical data now used. It is my view that we should begin the 80's by analysis of the life analysis process itself. A few of the several questions that require answers are as follows:

1. Are we using the kind of historical data that is best suited to the life prediction problem?

2. Do the analysis techniques make best use of the data?

3. What degree of confidence should we have in using a historical extrapolation as a predictor of future events?

4. How could forward-looking information be best used and combined with historical data to improve the predictive capabilities of life analysis calculations?

Up to this point, I have considered only straight-line recovery methods. There is another aspect of the word timely which I would now like to address. The question is: is there a more suitable pattern of capital recovery when the actual decline in the value of assets proceeds at an accelerated pace. For example, the loss in value during the first year of an automobile's life may be quite different than the straight line method accrual. To illustrate this value-oriented concept further:

> Assume that a $100 investment in technology A by a regulated firm is expected to achieve a total service life of ten years (zero net salvage). Under straight line depreciation the net investment after five years would be $50. Further assume that, five years into the expected service life, a competing technology is available at an initial cost of $40. The economic value of technology A at that time is at most $40 not $50, and the accumulated depreciation should be at least $60 not $50.

With rapid technological innovations and increased levels of competition in both basic and non-basic markets, there will be the need for more consideration of changes in value in the capital recovery process.

In both a regulated and unregulated environment, the need for a value-oriented capital recovery method is especially important. Such a method needs to be developed to provide a basis for recovering capital consistent with the rate of consumption of value while assuring full recovery. In other words, the depreciation method would reflect in annual depreciation accruals the pattern of decline in economic value of assets each year.

Conclusion

I started my remarks by observing that we have come full circle to the need of re-examining, after a century, the changing premises of our depreciation and life analysis methods. I have attempted to share with you my thoughts on upcoming changes and some ways to address these changes in the depreciation process.

To summarize these thoughts, let us look at Figure 4. First and foremost, the methods of life analysis must be anticipatory and forward looking as compared to the current historically oriented analysis procedures. Secondly, the tools of technological and market forecasting must be improved and refined to enhance the supportability of estimates of future impacts. The investment categories for which separate depreciation rates are developed must be disaggregated to provide more accurate tracking of capital recovery for each specific type of investment. Broad categories may mask and obscure relevant developments for specific investment. Depreciation methods, which ensure both full and timely capital recovery, must be developed and utilized. Finally, the economic value of investment should be used as a measure of the appropriateness of the accumulated recovery. The undepreciated investment should always be equal to or less than its economic value.

In conclusion, we must refocus our depreciation and life analysis efforts in the 80's from the past to the future and develop the tools necessary to support and provide for capital recovery under uncertain and changing conditions.

Thank you.

SIGNIFICANT BELL SYSTEM DEPRECIATION REFINEMENTS

1884	Depreciation Accounting Introduced
1912	Collection Of Historical Data
1913	Straight-Line Group Method
1923	Gompertz-Makeham Formula Used For Mortality Analysis
1946	Straight Line Vintage Group Method Adopted
1950	Computed Mortality Introduced
1973	Straight Line Equal Life Group Method Proposed

Figure 1

MAJOR REGULATORY ACTIONS IN THE TELECOMMUNICATION INDUSTRY

1957	Hush-A-Phone Decision
1959	Above 890 Decision
1968	Carterphone Decision
1971	Specialized Common Carrier Decision
1973	Economic Impact - Docket 20003
1977	Terminal Equipment Registration
1979	Deregulation Of Competitive Domestic Telecommunications Markets Docket 79-252
1980	Computer Inquiry II Decision - Docket 20828

Figure 2

AVERAGE PRESCRIBED DEPRECIATION LIVES FOR PBX'S IN THE BELL SYSTEM, 1957-79

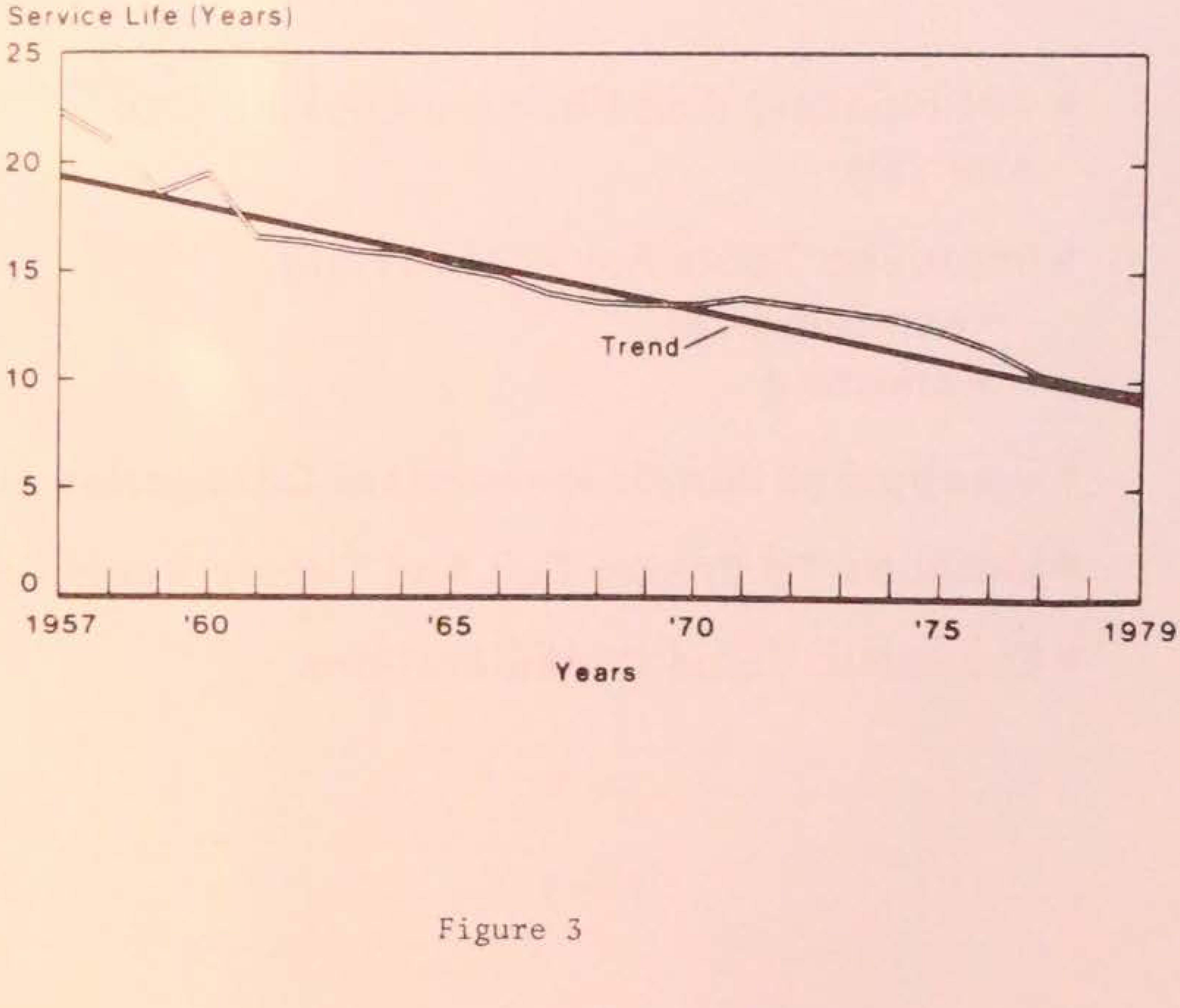


Figure 3

PROBLEMS IN FINANCING, SOLUTIONS AND THE REGULATORS' ROLE

Robert T. Symonds
Treasurer
Milford Water Company

For you who are involved with water companies, particularly small ones, I doubt if it is necessary for me to tell you that they have serious problems. I have come to believe that those problems are not well understood by a great many regulators. Nevertheless, you who regulate must find yourselves in the middle at times when small companies are unable to meet water quality standards, are unable to cope with growth or just cannot give good service.

Recently, a questionnaire was sent to utility commissions in all fifty states asking a number of questions. It was sent by the Water Committee of the National Association of Regulatory Utility Commissioners. Thirty-eight percent of the commissions replied that their greatest problem in regulating water companies is with small companies.

Water utilities are unique in their characteristics. Since this is not well understood, the resulting tendency may be to regulate these small companies according to the same rules used for large electric or gas utilities.

You are perhaps aware that there are a great many small water companies around. Even the largest companies do not compare with gas, electric or telephone, which usually cross political boundaries and average much larger in size. Water utilities usually serve only one town or city. Little was known about this until recently when EPA, concerned about the ability of water utilities to meet new water quality standards, hired a private firm to make a survey of the industry. Out of that came information that there are about 35,000 community water systems in the country serving 195 million people. Over 2/3 of that number serve less than 1,000 people. Sixty-one percent of those serving less than 1,000 are privately owned. That puts the number of small private water companies at over 14,000. Some of these are so small they may not be regulated by state utility commissions. But a great number are regulated, and the news getting to me is that many of them are troublesome for the commissions and no doubt for their customers. I am sure that the proposed Water Bank will not solve all the problems, but I am also sure that it should be a great new tool which, when coupled with adequate management and understanding regulation, should go a long way toward lifting water utilities to a better level of operation.

I would like first to talk about financing problems, then a quick review of the design of the Water Bank and finally about what you who are regulators or public advocates can do to help us put it all together to achieve the standards of drinking water quality mandated by the Safe Drinking Water Act and to accomplish a lot of other improvements that are certainly needed.

First of all I would like to point out that water utilities are not just the most capital intensive of all utilities by far, but that they have been said to be the most capital intensive per dollar of revenue of all industries. It takes a great deal of money to set up these utilities or to improve their facilities.

Now, when you couple typical small size with great need for capital, you have a problem. The large proportion of capital contributed by real estate developers is a symptom of that problem.

Institutional investors, such as insurance companies, have traditionally been the source of long-term debt capital in the past--even for some pretty small utilities. I can remember when just about every little water company in my area of New England had a bond issue outstanding at John Hancock Mutual Life Insurance Company. Loans there seemed almost automatic for the asking--and they were small loans. Not long ago the Barnstable Water Company, which serves Hyannis, and which I manage, paid off a $50,000 bond issue arranged at the John Hancock 20 years earlier. We could not renew the bond, even with a substantial increase in size and interest rate. The John Hancock is not now interested in any loan of less than 2 million dollars. A 4% sinking fund would probably be required. That is not exactly what small water company operators have in mind. With cash flow produced by 1½% or 2% composite depreciation and usually inadequate earnings, water companies could not meet interest and sinking fund requirements most of the time.

In defense of the insurance companies, it is probably as much trouble making and keeping track of a small loan as a large one. A senior loan officer at the John Hancock recently commented to me, "The Federal Water Bank is an excellent idea for small water companies."

A look at the earnings of companies with less than $50,000 annual gross revenue, reporting to the National Association of Water Companies, reveals that on average these companies had a net loss in four out of the last seven years reported. Who would lend them money anyway? Even Chrysler does not have that bad a record. This situation needs attention whether or not the Water Bank comes into being. The Water Bank, like any other bank, will expect that interest payments be met and that the long-term loans of the bank will be repaid.

The main advantages of a Federal Water Bank, if we can achieve it, will be that small size alone will not be a roadblock to a loan and that, at a time when the maturity of loans is being shortened, long-term loans will still be possible consistent with our long-lived facilities. The draft of legislation allows a maximum of 50 years. Interest rates will probably be at the cost of money to the Water Bank. As the bill is now written, the bank will also be able to provide management counseling as needed. Many small water companies do not go for rate relief when they should, nor do they understand what they should have for return on investment. It is my hope that bank counselors might counsel commissions as well as managers--at least notify commissions if and why credit is refused.

For instance--an example of why credit might be refused. Like any other business a water utility needs adequate cash flow to meet its obligations. Cash flow is provided mostly by money taken in to meet depreciation charges plus whatever earnings there may be. This is the money generated internally with which a company might make improvements or pay off loans incurred to make improvements. Commercial banks, in making short-term loans, are concerned primarily with the cash flow of a company. It is an indication of the company's ability to pay interest and principal on a loan. To accomplish that, both the depreciation allowance and net earnings must be adequate. It is my belief that, if we were to try to tag the main reason for inadequate performance of small water companies, it would be almost non-existent cash flow. In a small way it is an illustration of the capital formation problem so much talked about now.

Furthermore, I believe that inadequate cash flow is partly a management problem and partly due to misguided regulatory policy. Let me give an example of regulation that might prevent a company from receiving a loan, even from the Water Bank. With contributions in aid of construction making up a major part of plant investment in many water utilities, particularly small ones, some regulatory commissions are eliminating the allowance for depreciation on contributed plant. That depreciation contributes to the cash flow so badly needed in getting a loan and afterwards in servicing that loan. Commissions are troubled by the inability of small water companies to perform. How in the world do we end up with regulation that so seriously downgrades the ability of those companies to serve their customers adequately? Someday the company will have to replace the contributed plant. That may be when the fun really begins.

I manage a company called the Edgartown Water Company. It has 1,100 customers and $170,000 annual gross revenue. It is small but viable. Last year the company lost money due mostly to capital expenditures for water supply to meet increasing summer demand and accelerating interest on the bank loan incurred to do the job--up to 20% interest. Cash flow, the combination of depreciation and earnings, ended up a negative figure. (We have a rate case in progress.) When the water supply project was conceived three years ago, we were told that a $200,000 long-term note could probably be placed with an institutional investor to pay off a short-term construction loan. We were told even then that $200,000 was too small to place but that a small insurance company might be persuaded to take it because Edgartown is so famous. After all, many well-known people live or summer there, Chappaquiddick is part of Edgartown, the movie Jaws was filmed there and Edgartown along with other towns on the Island of Martha's Vineyard voted conspicuously to secede from Massachusetts and the Union too, if need be, when separate representation in the State Legislature was denied. What better qualification for a loan could a company have? Unfortunately, time flies and times change. Our fame is probably no longer good enough to place a $200,000 long-term note. We are sitting on the edge of our chairs, waiting for the Water Bank--and so is our banker.

So here is the Water Bank as it exists in the fourth draft and ready for introduction to the Congress at what may be the worst moment in history for such a petition. Can a congressman reconcile the Water Bank with his budget-balancing act? Perhaps so--the bank is intended to be self-supporting, and it was Congress that passed the Safe Drinking Water Act mandating quality water.

The Water Bank originally was modeled after the Rural Telephone Bank which was created in the early 70's. That bank has served the independent telephone companies well. I was told that the smallest loan was to a company with 27 subscribers and the largest loan was 65 million dollars. With the help of the bank, telephone service has been extended, equipment modernized and, quite interestingly, there has been a reduction in the number of companies due to consolidations under single ownership and management, either with or without physical connection of the telephone systems. This is the kind of progress that is needed in the water utility business.

The seed money or equity capital for the Water Bank comes originally from the Federal Treasury--2 billion dollars the first year in return for 20 million shares of class A, $100 par preferred stock, then 10 billion dollars more, in aggregate, over the next four years. Not bad seeding! The figures result from an EPA estimate that the industry will need 5 billion dollars per year to make everything right. In the bank bill the Treasury contribution has been reduced somewhat from the EPA estimate of 5 billion dollars annually simply because the EPA figure may seem alarming to Congress. Additional equity capital will be produced through the required purchase of class B stock by utility borrowers and by the purchase at will of class C stock by utilities wishing to do so. Class B and C stockholders will have voting privileges and will be eligible for dividends after dividend and other obligations to the Federal Treasury have been met.

To raise debt capital, the bank can sell debt obligations to the public, to institutional investors or to the Treasury up to 20 times the paid-in capital and surplus--equity, that is. The capital is thus provided.

What about borrowing? Either publicly-owned or investor-owned utilities may borrow. They may borrow directly from the Water Bank in Washington. I am told that borrowing from the Telephone Bank does not involve months of paperwork or red-tape but that it is quite simple. May we keep it so for the Water Bank.

Guarantees of water utility loans may be provided by the Water Bank to open wide the doors to local private banks so that the less sophisticated operator of a small water system may negotiate a loan with a local bank where he may already do business. Going to Washington for a loan might be a bit too much. In that regard I had a call from a staff member of the Vermont Commission one day. He called to inquire about the status of the Water Bank because a small Vermont water company needed more water supply and the source was to be Lake Champlain. There is plenty of water in Lake Champlain, but it would require full treatment. There seemed to be no way to raise the money. Thinking of that little system, tucked away in northern Vermont, it seemed necessary to open the doors to the entire private banking system with all its tremendous capital and convenience by providing guarantees. The Water Bank bill provides for a charge to a utility benefiting from a guarantee with the thought that a reserve should be created to pay off any defaulted loans. To keep the local banks liquid, the Water Bank may buy up water loans made by local banks, package them and resell them or issue securities backed by water loans. There is considerable flexibility in the design of the bank.

Originally, eleven directors will be appointed by the President of the United States, eight of whom shall be from water utilities. Four of these will be from government-owned utilities and four from investor-owned utilities. As paid-in capital and surplus from water utilities increase, directors will be voted in by class B and C stockholders. In other words, the bank will gradually become privately controlled and the government will withdraw its money and influence. It is designed to be controlled by and for the sole use of water utilities and is intended to become a private bank somewhat in the manner of Fannie-Mae in the housing industry. So much for the Water Bank.

What can regulators do to make it work? The bank has no grant program. Interest and repayment of principal must be honored in timely fashion. Why should customers be excused from water rates that are adequate to honor those obligations? The people who benefit should pay the bill. There is no free lunch.

Commissions do not allow earnings to pay off debt. They do allow depreciation and return on equity. These items have to produce the cash flow that make it possible for the utility to repay debt. Prevailing composite depreciation rates of water utilities of 1½% or 2% are not adequate for repayment nor are they equitable for investors because the dollars recovered through depreciation will not replace worn out plant as inflation increases replacement cost. The value of stockholders' dollars invested in water facilities is being eroded because of inadequate depreciation. The result is the mining of equity capital. Replacement depreciation is necessary to maintain the purchasing power of invested capital and, most important for these small companies, to provide the cash flow necessary to make water companies credit-worthy.

Small and medium-sized water companies are often loaded with contributed capital because that is the only capital they can get. Let me tell you a horror story to improve understanding of small water companies. Consider a hypothetical company with 100% contributed capital. Assume the commission does not allow depreciation on contributed capital. There is no equity on which to earn a return since all capital is contributed. There is then no cash flow whatsoever. Operating expenses, maintenance and local taxes are all that would be allowed in a rate proceeding. Assume that power cost for pumping increases. There are no earnings or depreciation. There is no cash flow with which to absorb the increased cost. The company cannot pay the power bill. The power goes off. The customers have no water. Will the power company credit department understand regulatory lag and the honest excuse that the water company will not be able to earn the money to begin paying the bill for another year or more? With no depreciation and no return on investment, water rates are very low. It is a public advocate's dream. But service is not all that great. In fact customers have no water. With zero cash flow there is no way the company can borrow to pay bills.

That scenario is not unlike a lot of small water companies where contributed capital is a major factor. James McGirr Kelly, formerly of the Pennsylvania Commission, said that sometimes small company owners just disappear. For a small operator there may be more headaches than rewards. With small personal investment and average poor return on what there is, with little or no cash to meet emergencies, with little chance of borrowing money without mortgaging his own house, probably with disturbing customer complaints and with little regulatory understanding, the owner's wisest course of action may be simply to get out of town--permanently.

What solutions are there? Slowdown in capital formation has become a national issue. In the case of small water companies capital formation would be a joke if it did not threaten the public health. Nationally mandated water quality standards will cost billions of dollars. Something has to give. Depreciation based on original cost and useful life is as obsolete as the dodo bird. Conditions have changed. Depreciation rates designed to recover invested capital at a rate at least equal to the repayment schedule of long-term debt is essential. In addition, the depreciation rate should include the recovery of equity investment in the same period allowed for tax purposes. We must stop thinking in terms of depreciation tied to service lives. Rather we must think in terms of recycling capital already invested and of the need to service debt.

Small water companies will continue to be an increasing problem for regulators if accelerated capital recovery through depreciation is not encouraged and if cumbersome regulatory processes are not made simple for the small operators. Water is usually cheap, but some small utilities are charging up to $600 annually per customer for water service--far above the average. That may be what is necessary. Such a charge is probably an indicator of intelligent regulation. The presence of coliform bacteria in water of a small supplier may become an indictment not only of the operator but also of the regulatory process in a given state. Coliform bacteria are politics in reverse.

Some signs of progress would be to:

1) Set depreciation rates based on replacement cost or to permit amortization of long-term debt and timely and adequate recovery of equity investment.
2) Index uncontrollable expenses. Small companies are extremely sensitive to increases in expenses and cannot perform during periods of losses.
3) Using simplified annual reports for the benefit of both operators and shorthanded commission staffs, grant annual rate increases if necessary to keep small operations viable. That might eliminate some disastrous 100% rate increases.
4) Allow depreciation on contributed plant. The resulting cash flow is extremely important. The utility has to replace the plant. If, as a regulator, you disagree with it philosophically, then allow it as a practical matter. It is better than coliform bacteria.
5) Regulate water companies as the different breed that they are: small, capital intensive, unable to raise capital and facing unreal EPA regulatory demands for water quality.
6) Support legislation creating the Federal Water Bank by contacting your congressman at the proper time.
7) Deregulate utilities with fewer than fifty connections. A group as small as that should talk about problems on a one-to-one basis.

FINANCING WATER SYSTEMS IN THE 1980's

Harry G. Kivell

Vice President

Robert W. Baird & Co., Incorporated

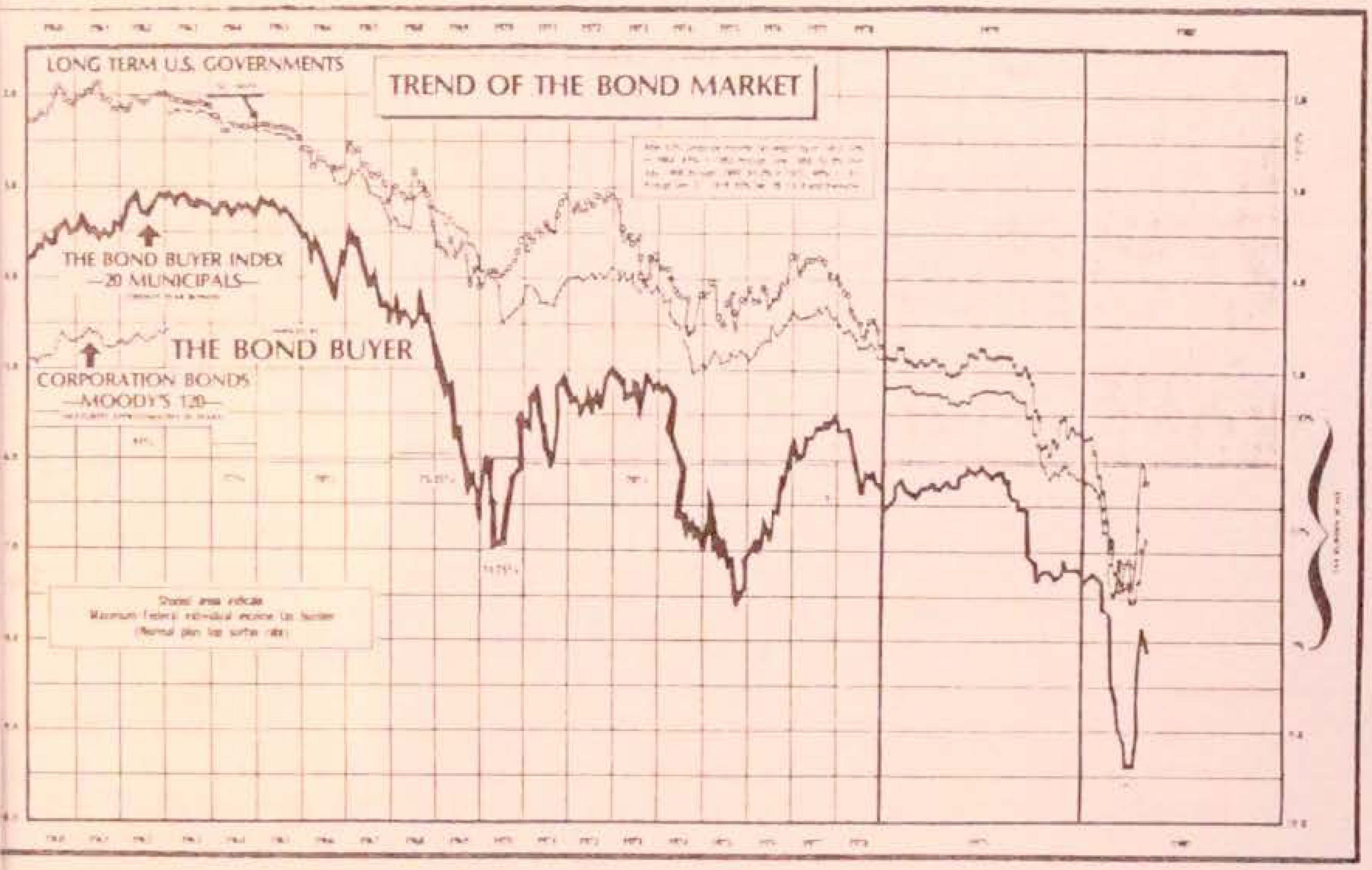
The costs of a municipal water system in providing a safe and dependable water supply, are increasing substantially each year. With increasing Federal and State government involvement providing more stringent requirements, the costs thereof are escalating at rates at, or exceeding, the inflation rate of the economy. Heavy pressure on wastewater systems also have had their impact on water systems by heavily utilizing engineering and contractors time.

The development of new sources of supply for water systems has increased in cost significantly. The Safe Drinking Water Act of 1978 with its requirements on the presence of organic materials, has increased the treatment requirements for surface water. This is much more suspect in the light of treatment costs and water standards. Deep well construction has also increased considerably in cost over the past decade. Site selection becomes more critical in the effort to tap new strata for the proper supply necessary for today and future demands. Storage facilities, whether they be underground or elevated, have become much more important. Pressure demands for fire protection and the resultant effects on insurance rates, as well as future planned development, demand facilities that create proper pressures as well as supply.

In the United States today we have seen a substantially reduced birth rate and a declining population. Our society however, has become very mobile resulting in population shifts. With this movement many communities throughout the country will continue to be faced with the extension and creation of new services. It is extremely important that all communities have a subdivision ordinance to protect the erosion of future utility earnings.

At present, we are in one of the most volatile money markets this Country has seen. Measured by the Bond Buyer Index of 20 municipal bonds, interest rates have fluctuated by almost 2½ percent within the first four months of this year. In comparison, during the entire year of 1977, the index varied by less than one-half of one percent.

Inflation, Federal fiscal policy and the Federal Reserve monetary policy have had significant impacts on the bond market over the past fifteen years. In the years 1966 - 1970 - 1975 and again in March 1980 we have had interest rate peaks with each somewhat higher than the previous peak. It is significant to note that after each peak, although interest rates have dropped, they have never dropped to the previous level. The graph illustrated below demonstrates this fact:



The above graph and interest rates relate to general obligation municipal bonds. Water utilities are not limited however to only general obligation bonds but have the additional options of utilizing either revenue or special assessment obligations. On line and service extensions, special assessments and related financing for the installments is quite often the fairest method allowing those who are being benefited to pay the costs incurred. For major system improvements such as wells, storage facilities and treatment plants, either revenue or general obligation bonds would best be utilized.

What considerations should be given in determining which method of financing should be utilized? A prime consideration should be the useful life expectancy of the improvements. General obligation bonds usually have a much shorter maximum maturity than revenue obligations. For instance, in the State of Wisconsin all general obligations must be repaid within twenty (20) years. Conversely, most water utility improvements are depreciated over a forty (40) to fifty (50) year life. With this disparity between depreciated life and maturity schedule, the utility earnings are severely burdened and its ability to be self sufficient is undermined when general obligation debt is issued. Revenue debt however, can be set over a longer period of time, more nearly approximating the expected life of the project improvements. The issuance of revenue bonds, in most states, are excluded from constitutional debt limitations; this makes for greater acceptability by city and village boards. Revenue bonds also insure that the repayment of the debt and its interest will be accomplished on a proportionate basis to the use of the services provided.

Revenue bonds are issued under and authorized by an ordinance with a life comparable to the bond issue (30 to 40 years). Therefore, the terms of this document are extremely important to the future life and operations of the system. Flexibility in the terms and regulations of the ordinance is essential. In fact, flexibility in the ordinance is in most cases more important than the rate of interest paid on an individual issue. The issuance of future debt on a parity and expansion of the system through earnings generated therein could result in substantial reprecussions in the future.

Our experience, particularly in Wisconsin, has shown us that many utility commissions have not received a reasonable rate of return over a period of years. In fact, many have been operating at a deficit. This creates two basic problems. First, there are no internally generated funds to pay for small expansions as well as normal replacement and repair. Secondly, when the system is requested to extend services or required to replace worn out equipment the quantity of earnings necessary to substantiate a revenue bond is not there. To eliminate these problems a consistant program of earnings anaysis and rate increase requests is essential. Let us not forget that the utility is a business owned and operated by the municipality, and therefore should yield a reasonable rate of return.

We have been discussing market conditions, past and present, various financing vehicles, ordinances, rates, etc. Now the question we wish to consider is future market conditions. Of course in looking at the future, we must realize that rates of inflation, Federal fiscal policies and the Federal Reserve monetary restraints may substantially alter any forecasts. We have, apparently, recently embarked on a downward trend in interest rates. No trend will be smooth, for the market always over reacts. We would anticipate however, lower interest rates over the balance of this year and extending into 1981. We are already hearing from Washington the cries for spending, tax cuts and deficit spending to stimulate the economy once again. In a national election year the voice gets louder. This leads to the belief that inflation, if somewhat retarded, will continue. It appears that Federal Reserve monetary policy, the only constraint utilized to date, will once again come to the forefront and substantially effect interest rates. Historically this has happened approximately every five years. It is questionable whether this five year trend will continue. If the stimulus is applied too rapidly and inflation does not subside sufficiently, we may see the monetary restraints faster than in the past. We would also anticipate higher succeeding peaks in the interest rate cycles.

These consideration, as well as the economic outlook, imply that careful consideration must be made by all utilities as they relate to future financing, its type and maturity schedule and most importantly - - - timing.

SIXTEENTH SESSION, Thursday, May 22 - 10:15 p.m.

Concurrent Session G-1

PROJECT AND OTHER SPECIAL FINANCINGS

CHAIRMAN: Joseph M. Quigley, Financial Vice-President
and Secretary
NICOR, Inc.
Board of Directors, Iowa State Regulatory Conference

SPEAKERS: D. Barry O'Connor, Senior Vice President
Blyth Eastman Paine Webber, Inc.

Newton I. Waldman, Vice President
M & W Resources Division
Keith Feibusch & Company

Leveraged Leasing

of

Large-Scale Generating Facilities

D. Barry O'Connor
Senior Vice President

Blyth Eastman Paine Webber
Incorporated

I. A Perspective of Leasing

A. Theory

1. A Company which desires the use of an asset or a group of assets may consider leasing as an alternative to ownership.

2. If a lease extends for the entire useful life of an asset, the lessee has obtained as much use of the asset as would have been available through ownership.

3. If the lease has given the lessee complete operational freedom with respect to the asset, the only significant differences between leasing and buying relate to the after-tax cost of each alternative.

4. In many cases, leasing can provide a significantly lower after-tax cost than ownership through more effective use of tax benefits such as accelerated depreciation and investment tax credit.

5. In other cases, leasing can provide a comparable or slightly lower after-tax cost than ownership while enabling a lessee to obtain increased financing flexibility in other areas.

B. History

1. Although the concept of leasing is ancient, leasing did not become generally accepted as a legitimate means of financing until after World War II.

2. Transportation Equipment and later real estate were the areas in which many of today's leasing concepts were developed.

3. Many early leasing transactions were structured as leases for security reasons, rather than in order to obtain tax advantages. Other so-called "beneficial" lease financings were arranged primarily for balance sheet reasons. Both these types of leases are generally referred to as "financing" rather than "true" leases.

4. The tax-oriented "true" lease, where tax benefits are claimed by the lessor rather than the lessee, was pioneered in the real estate area and investors and lessees quickly realized its broad application to equipment financing. Banks, finance companies and private individuals actively sought the tax benefits available through this type of investment, particularly where their investments could be "leveraged" by borrowing a large percentage of equipment cost.

5. Today, leasing is a sophisticated, multi-billion dollar industry involving ever-growing numbers of lessees, investors types of leases and types of leased assets. In the utility industry, virtually all utilities have done some sort of lease financing and virtually every type of asset has been leased, including:

* service and maintenance vehicles;
* office and headquarters building;
* computers and other data processing equipment;
* coal mining and handling equipment;
* rolling stock and fuel barges;
* nuclear fuel cores;
* pollution control equipment;
* substations;
* turbines;
* transmission facilities; and
* entire baseload generating facilities

II. Overview of Leveraged Leasing of Large-Scale Generating Facilities

A. Description:

A leveraged lease of a large-scale generating facility is a "true" lease where an entire project is acquired by a group of equity investors, and leased back to the sponsoring utility or utilities. The equity investors leverage their investment in the project and pass through to the lessee, in the form of lower lease rentals, part of the value of the tax benefits inherent in the ownership of the project, principally the investment tax credit and the deductions for accelerated depreciation.

An economic prerequisite for this type of financing is usually that the tax benefits of ownership can be used more effectively by the equity investors than by the lessee.

B. Structure:

Equity investors acquire the project to be leased prior to its in-service date (for tax purposes) through a special-purpose ownership trust or partnership. The equity participants' investment must equal at least 20% of the cost of the project. The balance is obtained by the owner trust or partnership through the issuance of long-term secured notes. The debt financing is without recourse to the equity investors and is secured only by a mortgage on the project and an assignment of the lease and all rentals. The equity participants' return on investment is derived from (a) the net cash flow available from lease rentals in excess of debt service, (b) the tax benefits of ownership, and (c) the residual value of the project which will belong to the equity participants at the end of the lease term. A flow diagram of a leveraged lease structure is included as Figure I.

C. Economic Effect:

A common threshold measure of the economic effect of a lease is a comparison of the pre-tax cost of leasing (the rate that discounts the lease rentals to the present value of the project) and the pre-tax cost of ownership as measured by the lessee's incremental interest rate on long-term secured borrowings. Since both rates are a function of the credit of the lessee, it is commonly accepted that this "spread," which often ranges between 300 and 500 basis points, provides a meaningful indication of the cost advantage of leasing. However, the true measure of the economic effect of a lease must be calculated on an after-tax basis after taking into consideration the loss of the lessee's tax benefits of ownership and its residual interest in the project. If a lessee is able to fully utilize the tax benefits of ownership, then leasing will probably be more costly than ownership.

III. Advantages and Disadvantages of Leasing Large-Scale Generating Facilities

A. Advantages:

1. Leveraged leasing may enable a utility which has a low effective tax rate to share currently part of the value of tax benefits which would otherwise be deferred or lost entirely, thereby resulting in a significantly lower after-tax cost than ownership.

2. Leveraged leasing provides 100% financing for a project and defers the need for concurrent public financings.

3. It improves the lessee's cash flow during the first half of the lease relative to debt service payments.

4. It prevents dilution of earnings per share in those cases where the lessee would otherwise be required to issue common stock at less than book value.

5. Leveraged leasing frequently represents a new source of funds, thus conserving traditional credit resources for other uses.

6. Leveraged leasing may permit financing which would otherwise be prevented by restrictive indenture convenants.

7. Leveraged leasing usually results in off-balance sheet financing.

8. Lease rentals are usually fully recoverable as a "cost of service"; therefore, the utility avoids further dilution if it is not earning its allowed rate of return. Also, regulatory lag is minimized.

9. By entering into the lease at the inception of construction, the lessee may arrange construction financing and long-term financing at the same time.

B. Disadvantages:

1. Leasing can be more expensive than conventional financing if the lessee can fully utilize the tax benefits of ownership.

2. In the event the lease is treated as an off-balance sheet financing, the danger exists of over-leveraging.

3. If treated as an "operating lease", the asset generally will not be included at full value in the lessee's rate base.

4. The lessee relinquishes the residual value of the project (although the lessee never loses control of the asset nor the right to purchase the asset or renew the lease for the remainder of the project's economic life).

5. The lessee may be required to give up some operating flexibility with respect to the maintenance or improvement of the project.

6. Leveraged leasing is generally more complex, time consuming and costly to document than conventional financing.

IV. Evaluating and Structuring a Leveraged Lease Financing

A. Feasibility Study

An important first step in evaluating the merits of a leveraged lease is a Feasibility Study consisting of, at a minimum:

* an economic and market review;
* an analysis of the expected tax and accounting treatment;
* a study of legal considerations as they relate to the utility's indenture and/or loan agreements; and
* a survey of all regulatory matters.

1. The economic analysis is essentially a lease vs. buy calculation that compares the after-tax cost of leasing with the after-tax cost of ownership. This can be done either by (i) a discounted cash flow (DCF) analysis, or (ii) a revenue requirements analysis.

a. the DCF analysis, which is most commonly used in non-regulated industries, should accurately reflect in each year the utility's ability to use the tax benefits of ownership (i.e., its effective tax rate). The after-tax cash flows of leasing and owning are calculated for each year and then discounted by a rate which measures either the utility's cost of capital or its "opportunity cost". The decision will be based on the alternative having the lowest net present value cost.

b. the revenue requirements analysis, which is relevant only in a regulated industry, is calculated on a pro forma basis to ascertain which alternative results in the least revenue requirements or rate relief. In this analysis, all tax considerations are automatically reflected through the operation of the pro-forma model.

c. in either case, a realistic renewal rent or purchase price must be ascribed as a charge against leasing to reflect the loss of the residual value upon expiration of the lease term.

(Note: Whether the purchase alternative is considered to be financed by 100% debt or a blend of debt and equity financing is a matter of theoretical dispute. However, if a blended cost of capital is used to describe the purchase alternative, then it is arguable that a large lease financing should be charged with a "cost of compensating equity" in recognition of the additional leverage created by the lease).

2. The significant tax question addressed in the structuring phase is whether the transaction qualifies as a "true lease" pursuant to the leveraged lease guidelines issued by the Internal Revenue Service in Revenue Procedures 75-21 and 76-30. (Copies are attached as Attachments I and II.)

a. Rev. Proc. 75-21 sets forth guidelines for the issuance of advance rulings in leveraged lease transactions. The guidelines deal with issues such as:

(1) the minimum, unconditional "at risk" investment;
(2) unwinds, puts and purchase options;
(3) residual values and the sharing thereof;
(4) profit requirements of the lessor; and
(5) the financing of cost overruns and lessee improvements.

(Note: The IRS has recently taken a "no-ruling" position regarding credit undertakings to support lease payments given by a person who is <u>not</u> a member of the Lessee Group).

b. Rev. Proc. 76-30 deals with limitations on the leasing of "limited use property." Provided that the lessor receives adequate back-up support from the lessee, the leasing of complete generating facilities will not be categorized as "limited use property," so long as the output of the facility can be interconnected into a utility power grid. The "Wyodak" and "Encina-5" leveraged leases are recent examples that confirm this proposition.

c. Rev. Proc. 79-48 modifies certain provisions of Rev. Proc. 75-21 and liberalizes the rules relating the circumstances under which a lessee may furnish the cost of improvements, modifications and additions to the leased property after it has been placed in service.

3. The accounting treatment of leveraged lease transactions is dictated by Statement No. 13 of the Financial Accounting Standards Board. (A synopsis of FASB #13 is attached as Attachment III.) To be categorized as an operating or off-balance sheet lease, the transaction must:

a. not transfer ownership to the lessee prior to the end of the lease term;
b. not contain a bargain purchase option;
c. have a lease term of less than 75% of the estimated economic life of the property; and
d. be priced such that the present value of minimum rentals, is less than 90% of the cost of the property less the investment tax credit.

(1) the discount rate to be used is the "rate implicit in the lease" -- if known -- or else the lessee's incremental borowing rate.

(2) since a lessor will usually not disclose his implied rate, a prevailing trend among auditors is to estimate the "rate implicit in the lease" based on an imputed, reasonable residual value.

4. The legal considerations should be addressed by lessee's counsel to ensure that nothing exists in the lessee's Indenture or Loan Agreements that would preclude entering into a leveraged lease transaction.

This should include:

a. a review of standard closing opinions customarily given by counsel to the lessee;
b. ensuring that the project can be released from the lien of the First Mortgage Indenture; and
c. ensuring that all contracts, permits and approvals can be assigned to, or obtained in the name of, the owner/lessor.

5. The proposed transaction should be screened with appropriate regulatory authorities to determine:

a. their disposition towards leveraged leasing; and
b. the expected rate-making treatment.

B. Packaging the Credit

1. Some lenders perceive lease obligations as indirect credit financings that rank (from a rating and pricing standpoint) one level below the lessee's First Mortgage Bonds.

2. To mitigate this perception, the investment banker should emphasize the credit inherent in the project and the lease structure itself, including:

a. the intrinsic value of the new plant (typically, the most efficient in the lessee's system);
b. the negligible technological risk of a fossil-fired plant;
c. the "resale value" of the plant (or the power output) based on operating and wheeling agreements given by the lessee to the owner/lessor;
d. the lower cost resulting from the lease; and
e. lease payments being fully recoverable as a cost of service and not being subject to diminution if earnings are less than that allowed.
f. a strong argument can be made that a lease obligation is stronger than a First Mortgage Bond.

3. The credit analysis of the lessee should focus not only on traditional financial measures, but also on:

a. the regulatory climate in the lessee's service territory;
b. fuel resources available to the lessee;
c. the historical and projected growth rates for both the lessee and the geographic area in which the lessee operates; and
d. the existence, if any, of non-cancelable, long-term power sales agreements with major industrial customers.

4. The transaction should be structured to appeal to the broadest possible market.

a. ensure that life insurance companies are able to participate as equity investors; and
b. avoid "legal investment" limitations of the institutional lenders.

C. Placing the Equity and Debt Portions of the Leveraged Lease

1. Generally, the lessee's interests will be best served by engaging an investment banker to serve as "Project Manager." The investment banker:

a. acts solely as the lessee's agent with respect to both the debt and equity investors;
b. is not an equity participant subject to conflicts of interest;
c. assists the lessee in evaluating, negotiating and, if necessary, restructuring bid proposals;

d. works closely with lessee's counsel (internal or special project counsel) in negotiating lease terms and conditions;

e. acts as a buffer between prospective investors, lenders and the lessee; and

f. coordinates the documentation process and the closing mechanics.

2. Equity solicitations

a. the demand of the equity market will normally permit large leveraged lease transactions to be marketed in the basis of a request for proposals rather than on a pre-priced basis.

b. an offering brochure should be prepared that will solicit proposals from selected lead investors on a comparable basis.

    (1) limited, but competitive bids should be received based on common specifications.
    (2) avoid over-structuring the transaction when soliciting bids.

c. upon receipt of proposals, the bids should be evaluated for comparability, completeness and reasonableness of the underlying assumptions. At this point, it may be necessary to suggest structural modifications (designed to lower the lease rate) with regard to:

    (1) debt amortization schedules;
    (2) different maturities for the lease and/or debt;
    (3) stepped rental payments;
    (4) salvage value assumptions;
    (5) liability for the payment of transaction fees and expenses; and
    (6) stipulated loss and termination value schedules.

d. next, focus on negotiating principal terms, conditions and indemnification events.

e. upon selection of a lead equity investor (or investor group), execute a detailed commitment letter that contains agreement (for documentation purposes) on issues such as:

(1) specific events of indemnification and reverse indemnification;
(2) the method of calculating indemnification payments and rental adjustments;
(3) establishing a completion fund to pay costs incurred after the project's in-service date;
(4) procedures for financing subsequent improvements and modifications;
(5) renewal and purchase options;
(6) provisions for self-insurance;
(7) fuel supply agreements; and
(8) conditions precedent to the takedown of equity funds.

3. Debt placement

a. in many ways, this is similar to a conventional private placement.

(1) solicit selected lead investors at a suggested interest rate;
(2) solicit the balance of the requirements from lenders at the rate negotiated with the lead lender(s);
(3) the total number of lenders will be determined mainly by the size of the transaction. Few additional problems arise from having a large lending group.

b. an unrealistic rate should not be pressed in a large financing of this type. By pressing the interest rate, the danger exists of chasing the market through rate levels that could have been achieved earlier.

c. prior to the receipt of commitment letters, the lessee and its agent should negotiate principal terms and conditions such as:

(1) security arrangements;
(2) indemnifications;
(3) pledging indemnification payments due to the lessor in the event of a default by the lessee;
(4) issuance of additional debt; and
(5) prepayment and/or refunding provisions; and
(6) adjustment in the percentage of leverage to accommodate overruns or post-completion expenses.

d. some leveraged lease financings can utilize publicly sold debt.

(1) a series of pollution control bonds may be incorporated into the leveraged lease structure;
(2) there is no compelling reason why all of the debt would not be publicly sold but SEC complications may arise;
(3) using publicly sold debt may simplify the negotiation of terms and conditions.

4. The equity and debt placements can be significantly enhanced by:

a. pre-marketing efforts by both the company and by the financial project manager;
b. solicitation of experienced investors and lenders as lead participants;
c. ensuring that the lead investors and lenders have a negotiating mandate (by virtue of either their participation interest or their leadership position) from other members of their respective groups; and
d. a coordinated flow of information to keep all parties abreast of new developments.

D. Closing the Transaction

1. Documentation should commence immediately after the execution of commitments for the equity and debt portions of the lease.

a. agree upon the selection of counsel to represent the various parties.
b. appoint the drafting team and apportion responsibilities.
c. establish a time schedule and adhere to it as much as possible.
d. agree upon a documentation format and, to the extent possible, use existing documents as a reference.
e. ensure that business points are decided by principals and not left to attorneys.

2. Concurrently with the documentation process, the lessee should obtain all necessary permits, licenses, approvals, assignments, etc.

3. If required, the advance ruling from the IRS should be requested as soon as the documents are in substantially final form.

a. an average of four to six months should be allotted to receive a ruling.
b. there is no substitute for counsel experienced in this area!

4. Coordination among the participants is key to a successful closing and imperative with regard to:

a. the logistics of executing final documents in counterparts;
b. filings and recordings made upon closing;
c. the transfer of funds on the closing date.

V. Rating Agencies and Regulatory Authorities

A. Rating Agencies

1. No preconceived bias against leveraged leasing per se, although a philosophical aversion seems to exist regarding the leasing of base-load generating facilities that are excluded from rate base.

2. Leases are viewed as debt obligations that rank somewhere below First Mortgage Bonds with regard to fixed-charge calculations for rating purposes.

3. To the extent that leasing is not used as a means of overleveraging, then the aversion cited above is mitigated. This is particularly true when a lower financing cost can be demonstrated.

4. To avoid over-leveraging, the lessee should undertake to issue additional equity (to finance new projects) "within a reasonable period of time."

5. Leasing should not be used to circumvent "protections" contained in the mortgage for bondholders.

B. Public Utility Commissions (PUC)

1. In the face of rising electric rates, many PUC's insist that utilities explore "innovative (project) financing techniques" as a means of reducing revenue requirements.

2. Strictly speaking, the savings resulting from an operating lease accrue solely to the ratepayer. Therefore, utilities have little incentive to employ leveraged leasing unless:

a. the project is included in rate base; or
b. the PUC authorizes a higher than normal return on equity to compensate stockholders for the (perceived) increase in risk and leverage. Certain commissions have already adopted this policy with respect to leases of generating facilities.

3. The Arizona Corporation Commission has authorized the leveraged lease of a combined cycle generating facility to be included in the lessee's (Arizona Public Service Company) rate base.

C. Securities and Exchange Commission (SEC)

1. Generally, the SEC will exempt the owner/lessor from jurisdiction under the Public Utilities Holding Company Act of 1935 so long as it remains a "passive" owner and so long as the lease has been approved by the state regulatory authority having jurisdiction over the lessee.

2. The SEC is presently reviewing its position with regard to the balance sheet treatment of leveraged leases.

a. the SEC should abide by the accounting treatment dictated by FASB Statement No. 13.

b. however, under the Addendum to Accounting Principles Board Opinion No. 2, the accounting treatment in a regulated industry must follow the rate-making treatment. Therefore, a lease that is treated for regulatory purposes as an operating lease should be treated in a similar manner by the SEC.

I. Summary

* Leveraged leasing of large-scale generating facilities should be considered as a viable financing alternative but one with limited applications. It is essentially a tax-saving technique -- not a financial panacea or a medium to achieve off-balance sheet financing.

* To determine its suitability, a comprehensive feasibility study should be undertaken to evaluate the economic, tax, legal, accounting and regulatory issues.

* Allow 12-18 months for the evaluation, solicitation and documentation of a large leveraged lease financing. Sufficient advance planning will avoid last-minute problems.

* Leveraged leasing of entire generating facilities is an extremely complex and specialized method of financing. Unless one has a proclivity towards suicide, seek help from profes- sionals expert in this field.

ATTACHMENT 1

IRS TECHNICAL INFORMATION RELEASE 1302, APRIL 11, 1975, ON REV. PROC 75-21, SETTING GUIDELINES FOR ADVANCE RULINGS "LEVERAGED" LEASES OF PROPERTY
(TEXT)

The Internal Revenue Service today announced that a Revenue Procedure will be published to set forth guidelines that the Service will use for advance ruling purposes in determining whether certain transactions purporting to be leases of property are, in fact, leases for Federal income tax purposes.

The Revenue Procedure will appear in Internal Revenue Bulletin No. 1975-18, dated May 5, 1975.

PART III

ADMINISTRATIVE, PROCEDURAL, AND MISCELLANEOUS MATTERS

26 CFR 601.201: Rulings and determination letters. (Also Part I, Sections 38, 61, 162, 167; 1.38-1, 1.61-1, 1.162-1, 1.167(a)-1.)

Rev. Proc. 75-21

SECTION 1. PURPOSE

The purpose of this Revenue Procedure is to set forth guidelines that the Internal Revenue Service will use for advance ruling purposes in determining whether certain transactions purporting to be leases of property are, in fact, leases for Federal income tax purposes. The type of transaction covered by this Revenue Procedure is commonly called a "leveraged lease." Such a lease transaction generally involves three parties: a lessor, a lessee and a lender to the lessor.

In general, these leases are net leases, the lease term covers a substantial part of the useful life of the leased property, and the lessee's payments to the lessor are sufficient to discharge the lessor's payments to the lender.

SECTION 2. BACKGROUND

Section 4.01 of Rev. Rul. 55-540, 1955-2 C.B. 39, sets forth certain conditions that, in the absence of compelling factors of contrary implication, would warrant treatment of a transaction for Federal income tax purposes as a conditional sales contract rather than a lease of equipment. See Rev. Rul. 55-541, 1955-2 C.B. 19; Rev. Rul. 55-542, 1955-2 C.B. 59; and Rev. Rul. 57-371, 1957-2 C.B. 214, for examples of transactions determined to be sales rather than leases.

See Rev. Rul. 60-122, 1960-1 C.B. 56, for two transactions, ne considered a lease and the other considered a sale. See also ev. Rul. 72-408, 1972-2 C.B. 86, concerning the Federal income tax onsequences of a transaction cast in the form of a lease subsequently etermined to be a sale.

ECTION 3. NATURE OF THE PROBLEM

Rev. Rul. 55-540, cited in Section 2, provides guidelines or determining the existence of a conditional sales contract but oes not contain guidelines for determining the existence of a lease. he guidelines set forth in Section 4 of this Revenue Procedure are eing published to clarify the circumstances in which an advance ruling ecognizing the existence of a lease ordinarily will be issued and thus o provide assistance to taxpayers in preparing ruling requests and o assist the Service in issuing advance ruling letters as promptly as racticable.

These guidelines do not define, as a matter of law, whether a ransaction is or is not a lease for Federal income tax purposes and re not intended to be used for audit purposes. If these guidelines re not satisfied, the Service nevertheless will consider ruling in ppropriate cases on the basis of all the facts and circumstances.

ECTION 4. GUIDELINES

Unless other facts and circumstances indicate a contrary intent, or advance ruling purposes only, the Service will consider the lessor n a leveraged lease transaction to be the owner of the property and he transaction a valid lease if all the following conditions are met:

(1) MINIMUM UNCONDITIONAL "AT RISK" INVESTMENT

The lessor must have made a minimum unconditional "at risk" nvestment in the property (the "Minimum Investment") when the lease egins, must maintain such Minimum Investment throughout the entire ease term, and such Minimum Investment must remain at the end of the ease term. The Minimum Investment must be an equity investment (the 'Equity Investment") which, for purposes of this Revenue Procedure, ncludes only consideration paid and personal liability incurred by he lessor to purchase the property. The net worth of the lessor must e sufficient to satisfy any such personal liability. In determining he lessor's Minimum Investment, the following rules will be applied:

(A) Initial Minimum Investment. When the property is first placed in service or use by the lessee, the Minimum Investment must e equal to at least 20 percent of the cost of the property. The Minimum Investment must be unconditional. That is, after the property is first placed in service or use by the lessee, the lessor must not be entitled to a return of any portion of the Minimum Investment through any arrangement, directly or indirectly, with the lessee, a shareholder of the lessee, or any party related to the lessee (within the meaning of section 318 of the Internal Revenue Code of 1954) (the "Lessee Group").

The lease transaction may include an arrangement with someone other than the foregoing parties that provides for such a return to the lessor if the property fails to satisfy written specifications for the supply, construction, or manufacture of the property.

(B) Maintenance of Minimum Investment. The Minimum Investment must remain equal to at least 20 percent of the cost of the property at all times throughout the entire lease term. That is, the excess of the cumulative payments required to have been paid by the lessee to or on behalf of the lessor over the cumulative disbursements required to have been paid by or for the lessor in connection with the ownership of the property must never exceed the sum of (i) any excess of the lessor's initial Equity Investment over 20 percent of the cost of the property plus (ii) the cumulative pro rata portion of the projected profit from the transaction (exclusive of tax benefits).

(C) Residual Investment. The lessor must represent and demonstrate that an amount equal to at least 20 percent of the original cost of the property is a reasonable estimate of what the fair market value of the property will be at the end of the lease term. For this purpose, fair market value must be determined (i) without including in such value any increase or decrease for inflation or deflation during the lease term, and (ii) after subtracting from such value any cost to the lessor for removal and delivery of possession of the property to the lessor at the end of the lease term. In addition, the lessor must represent and demonstrate that a remaining useful life of the longer of one year or 20 percent of the originally estimated useful life of the property is a reasonable estimate of what the remaining useful life of the property will be at the end of the lease term.

(2) LEASE TERM AND RENEWAL OPTIONS.

For purposes of this Revenue Procedure, the lease term includes all renewal or extension periods except renewals or extensions at the option of the lessee at fair rental value at the time of such renewal or extension.

(3) PURCHASE AND SALE RIGHTS

No member of the Lessee Group may have a contractual right to purchase the property from the lessor at a price less than its fair market value at the time the right is exercised. When the property is first placed in service or use by the lessee, the lessor may not have a contractual right (except as provided in section 4(1)(A) above) to cause any party to purchase the property. The lessor must also represent that it does not have any present intention to acquire such a contractual right. The effect of any such right acquired at a subsequent time will be determined at that time based on all the facts and circumstances. A provision that permits the lessor to abandon the property to any party will be treated as a contractual right of the lessor to cause such party to purchase the property.

(4) NO INVESTMENT BY LESSEE.

No part of the cost of the property may be furnished by any member of the Lessee Group. Nor may any such party furnish any part of the cost of improvements or additions to the property, except for improvements or additions that are owned by any member of the Lessee Group and are readily removable without causing material damage to the property. Any item that is so readily removable must not be subject to a contract or option for purchase or sale between the lessor and any mber of the Lessee Group at a price other than its fair market value the time of such purchase or sale. However:

(A) Cost Overruns and Modifications. If the cost of property ceeds the estimate on which the lease was based, the lease may provide for adjustment of the rents to compensate the lessor for such additional cost (but see section 5.01 concerning uneven rent payments).

(B) Maintenance and Repair. If the lease requires the lessee maintain and keep the property in good repair during the term of e lease, ordinary maintenance and repairs performed by the lessee ll not constitute an improvement or addition to the property.

(5) NO LESSEE LOANS OR GUARANTEES.

No member of the Lessee Group may lend to the lessor any of the nds necessary to acquire the property, or guarantee any indebtedss created in connection with the acquisition of the property by e lessor. A guarantee by any member of the Lessee Group of the lese's obligation to pay rent, properly maintain the property, or pay surance premiums or other similar conventional obligations of a net ase does not constitute the guarantee of the indebtedness of the lesor.

(6) PROFIT REQUIREMENT.

The lessor must represent and demonstrate that it expects to ceive a profit from the transaction, apart from the value of or nefits obtained from the tax deductions, allowances, credits and her tax attributes arising from such transaction. This requirement met if:

the aggregate amount required to be paid by the lessee to or for the lessor over the lease term plus the value of the residual investment referred to in Section 4(1) (C) above exceed an amount equal to the sum of the aggregate disbursements required to be paid by or for the lessor in connection with the ownership of the property and the lessor's Equity Investment in the property, including any direct costs to finance the Equity Investment, and the aggregate amounts required to be paid to or for the lessor over the lease term exceed by a reasonable amount the aggregate disbursements required to be paid by or for the lessor in connection with the ownership of the property.

CTION 5. OTHER CONSIDERATIONS

.01 Leveraged lease transactions that satisfy the guidelines t forth in Section 4 hereof nevertheless may contain uneven rent ayments that result in prepaid or deferred rent. The Service ordinarily will not raise any question about prepaid or deferred rent if the nual rent for any year (i) is not more than 10 percent above or below e amount calculated by dividing the total rent payable over the lease rm by the number of years in such term, or (ii) during at least the rst two-thirds of the lease term is not more than 10 percent above r below the amount calculated by dividing the total rent payable over ach initial portion of the lease term by the number of years in such itial portion of the lease term, and if the annual rent for any year during the remainder of the lease term is no greater than the highest annula rent for nay year during the initial portion of the lease term and no less than one-half of the average annual rent during such initial portion of the lease term. Any ruling request involving uneven rent payments that do not satisfy the above exceptions must contain a request for a ruling as to whether any portion of the uneven rent payment is prepaid or deferred rent.

Any ruling issued by the Service as to the existence of a lease may contain an appropriate ruling or caveat as to such prepaid or deferred rent.

.02 The Service has not decided whether rulings will be issued with respect to property that is expected not to be useful or usable by the lessor at the end of the lease term except for purposes of continued leasing or trasfer to any member of the Lessee Group. Prior to the final decision, consideration will be given to any comments pertaining thereto that are submitted in writing (preferably six copies) to the Commisssioner of Internal Revenue at the address in Section 7 below by May 30, 1975.

Designations of material as confidential or not to de disclosed, contained in such comments will not be accepted. Thus, a person submitting written comments should not include therein material that is considered to be confidential or inappropriate for disclosure to the public.

It will be presented by the Internal Revenue Service that every written comment submitted to it in response to this request is intended by the person submitting it to be subject in its entirety to public inspection and copying in accordance with the same procedures as are prescribed in 26 CFR 601.702(d)(9) for public inspection and copying of written comments received in response to a notice of proposed rule making.

SEC. 6. EFFECTIVE DATE

The provisions of this Revenue Procedure are effectove with respect to those requests received after May 5, 1975.

SEC. 7. INQUIRIES

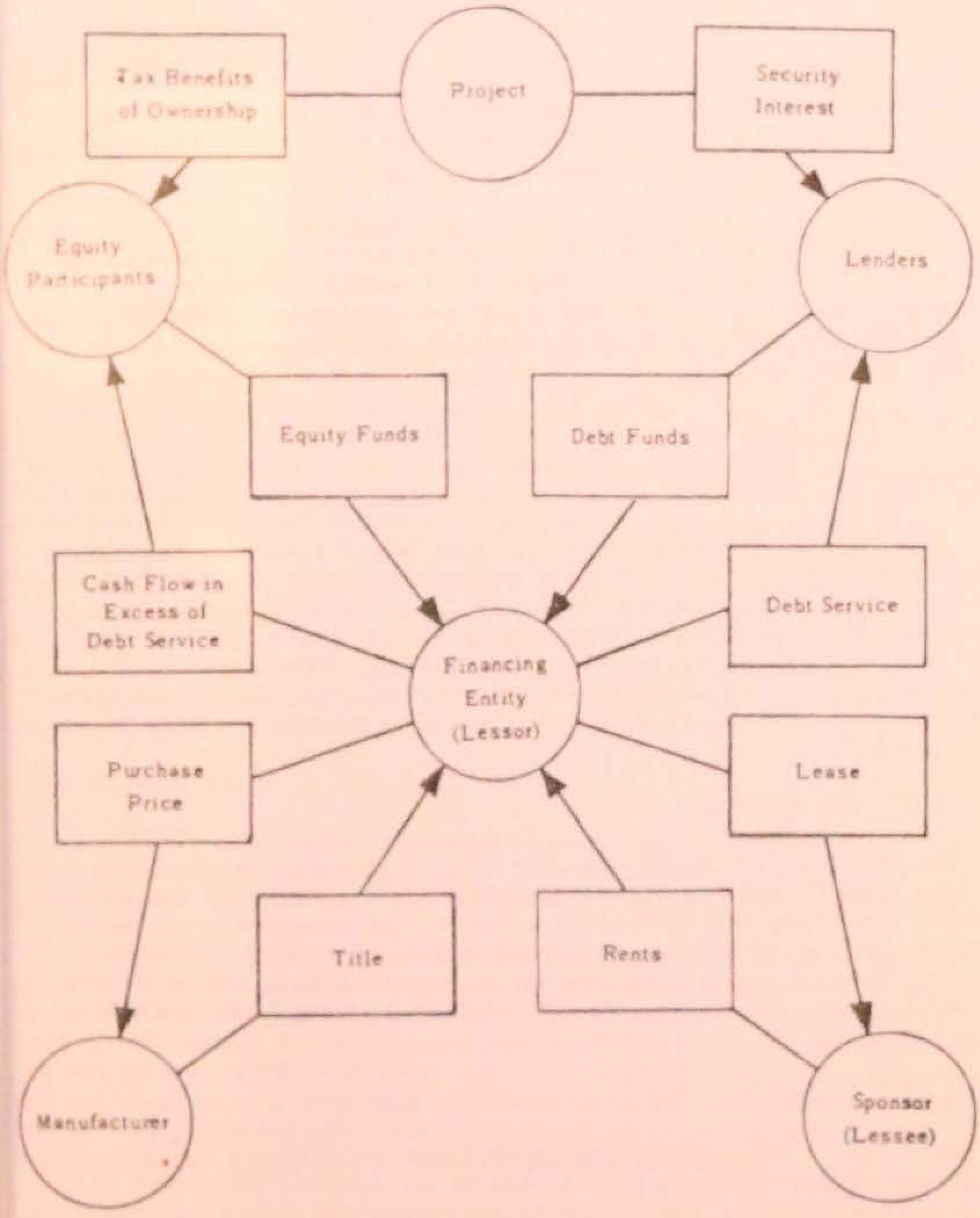
Inquiries regarding this Revenue Procedure should refer to its number and be addressed to the Commisssioner of Internal Revenue, 1111 Constitution Avenue, N.W., Washington, D.C. 20224, Attention: T:C:C.

--End of Text--

--End of Section 1--

FIGURE 1

LEVERAGED LEASE



ATTACHMENT 2

Revenue Procedure 76-30

.5527 Limited Use Property Leases (Advance Rulings).

(Full Text)

The Internal Revenue Service will not issue advance rulings that certain transactions involving leases of so-called limited use property are leases for Federal Income tax purposes, it was announced.

Limited use property is property not expected to be either useful to or usable by a lessor at the end of the lease term except for continued leasing or transfer to a member of the lessee group. The procedure stating the IRS decision contains examples illustrating both the types of property considered to be and not to be limited use property.

Rev. Proc. 76-30

Section 1. Purpose.

This Revenue Procedure concerns requests for advance rulings on leveraged lease transactions as described in Rev. Proc. 75-21, 1975-1, C.B. 715, and Rev. Proc. 75-28, 1975-1, C.B. 752. The purpose of this Revenue Procedure is to set forth the decision of the Service not to issue advance rulings that certain transactions purporting to be leases of property are, in fact, leases for Federal income tax purposes when the property is "limited use property."

Sec. 2. Background.

The Service previously announced in section 5.02 of Rev. Proc. 75-21 that it had not decided whether rulings would be issued in cases involving the leasing of property not expected to be useful to or useable by the lessor at the end of the lease term except for purposes of continued leasing or transfer to a member of the lessee group. Such property is referred to herein as "limited use property."

Sec. 3. Decision.

Rev. Proc. 75-21 sets forth guidelines relating to advance rulings on leveraged lease transactions. Section 4(1)(C) of those guidelines requires the lessor to represent and demonstrate certain facts relating to the estimated fair market value and estimated remaining useful life of the property at the end of the lease term. This requirement is intended, in part, to assure that the purported lessor has not transferred the use of the property to the purported lessee for substantially its entire life. In the case of limited use property, at the end of the lease term there will probably be no potential lessees or buyers other than members of the lessee group. As a result, the lessor of limited use property will probably sell or rent the property to a member of the lessee group, thus enabling the lessee group to enjoy the benefits of the use or ownership of the property for substantially its entire useful life. See Rev. Rul. 55-541, 1955-2 C.B. 19, for an example of a transaction in which property was determined to be leased for substantially its entire useful life and the conclusion that such a transaction transfers equitable ownership. Accordingly, the Service will not issue advance rulings whether certain transactions purporting to be leases of property are, in fact, leases for Federal income tax purposes when the property is limited use property.

Sec. 4. Procedure.

Pursuant to Rev. Proc. 75-28 taxpayers requesting an advance ruling in a leveraged lease transaction must furnish to the Service certain information and representations. If the information required to be furnished by section 4.09 of Rev. Proc. 75-28 fails to establish that the property is not limited use property, the Service will decline to issue an advance ruling on the transaction. Such information must establish to the satisfaction of the Service that the use of the property at the end of the lease term by the lessor or some person, other than a member of the lessee group, who could lease or purchase the property from the lessor, is commercially feasible to the lessor or to both respectively The Service's determination of commercial feasibility will be based on the standards that would be applied by reasonably prudent businessmen on the basis of present knowledge and generally accepted engineering standards.

Sec. 5. Examples.

The following examples illustrate the types of property the Service considers to be limited use property, and the types of property the Service does not consider to be limited for property.

(1) X builds a masonry smokestack attached to a masonry warehouse building owned by Y, and leases the smokestack to Y for use as an addition to the heating system of the warehouse. The lease term is 15 years; the smokestack has a useful life of 25 years and the warehouse has a remaining useful life of 25 years. It would not be commercially feasible to disassemble the smokestack at the end of the lease term and reconstruct it at a new location. The smokestack is considered to be limited use property.

(2) X builds a complete chemical production facility on land owned by Y and leases the facility to Y, a manufacturer of chemicals. The lease term is 24 years, and the facility has a useful life of 30 years. The land is leased to X pursuant to a ground lease for a term of 30 years. The technical "know-how" and trade secrets Y possesses are necessary elements in the commercial operation of the facility. At the time the lease is entered into no person who is not a member of the lessee group possesses the technical "know-how" and trade secrets necessary for the commercial operation of the facility. The taxpayers submit to the Service the written opinion of a qualified expert stating it is probable that by the expiration of the lease term of the facility third parties who are potential purchasers or lessees of the facility will have independently developed such "know-how" and trade secrets. The facility is considered to be limited use property. In reaching the conclusion, the Service will not take into account such expert opinion because such opinions are too speculative for advance ruling purposes.

(3) The facts are the same as in the example set forth in subsection (2) except X has an option, exercisable at the end of the lease term of the facility, to purchase from Y the "know-how" and trade secrets necessary for the commercial operation of the facility, and it would be commercially feasible at the end of such lease term for X to exercise the option and operate the facility itself. The facility is not considered to be limited use property.

(4) The facts are the same as in the example set forth in subsection (2) except it would be commercially feasible for the lessor at the end of the lease term to make certain structural modifications of the facility that would make the facility capable of being used by persons not possessing any special technical "know-how" or trade secrets. Furthermore, if such modifications were made, it would be commercially feasible, at the end of the lease term, for a person who is not a member of the lessee group to purchase or lease the facility from X. The facility is not considered to be limited use property.

(5) X builds an electrical generating plant on land owned by Y and leases the plant to Y. The lease term is 40 years, and the plant has an estimated useful life of 50 years. The land is leased to X pursuant to a ground lease for a term of 50 years. The plant is adjacent to a fuel source that it estimated will last for at least 50 years. Access to this fuel source is necessary for the commercial operation of the plant, and Y has recently obtained the contractual right to acquire all fuel produced from the source for 50 years. Y will use the plant to produce and generate electrical power for sale to a city located 500 miles away. The plant is synchronized into a powar grid that makes the sale of electrical power to a number of potential markets commercially feasible. It would not be commercially feasible to disassemble the plant and reconstruct it at a new location. The electrical

generating plant is considered to be limited use property because access to this fuel source held exclusively by Y is necessary for the commercial operation of the plant.

(6) The facts are the same as in the example set forth in subsection (5) except X has an option, exercisable at the end of the lease term of the plant, to acquire from Y the contractual right to acquire all fuel produced from the fuel source for the 10-year period commencing at the end of such lease term. It would be commercially feasible at the end of such lease term for X to exercise this option. Furthermore, it would be commercially feasible, at the end of such lease term, for a person who is not a member of the lessee group to purchase the contractual right to the fuel from X for an amount equal to the option price and purchase or lease the plant from X. The plant is not considered to be limited use property.

Sec. 6. Effect on Other Documents.

Rev. Proc. 75-21 is modified.

Sec. 7. Inquiries.

Inquiries in regard to this Revenue Procedure should refer to its number and be addressed to the Commissioner of Internal Revenue, Attention T:C:C, 1111 Constitution Avenue, N.W., Washington, D.C. 20224.

Rev. Proc. 76-30, 1976-2 CB 647.

ATTACHMENT 3

SYNOPSIS PREPARED BY COOPERS & LYBRAND OF
STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 13
"ACCOUNTING FOR LEASES"

In November, 1976, the Financial Accounting Standards Board issued Statement No. 13, "Accounting for Leases." The statement establishes standards of financial accounting and reporting for leases by lessees and lessors.

This statement supersedes APB Opinion No. 5, "Reporting of Leases in Financial Statement of Lessees;" APB Opinion No. 7, "Accounting for Leases in Financial Statements of Lessors;" paragraph 15 of APB Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock;" APB Opinion No. 27, "Accounting for Lease Transactions by Manufacturer or Dealer Lessors," and APB Opinion No. 31, "Disclosure of Lease Commitments by Lessees."

Accounting Series Release (ASR) No. 147 established disclosure requirements for leases for filings with the SEC. ASR No. 225 conforms SEC accounting and disclosure requirements to FASB No. 13.

The effective dates of FASB No. 13 and ASR No. 225 differ slightly. Statement No. 13 shall be effective for leasing transactions entered into after January 1, 1977. Annual and interim financial statements for fiscal years beginning after December 31, 1980, shall contain financial data to which the Statement has been retroactively applied. There are transition rules for the intervening period. Early application is encouraged but not required.

ASR No. 225 requires public companies to comply with FASB No. 13 for fiscal years ending after December 24, 1978, about three years faster than that required by Statement 13. The ASR covers all reports filed with the SEC and, although not mentioned specifically, all reports sent to shareholders. Compliance may be postponed if to do so violates a restrictive covenant in an existing loan agreement. Otherwise, early compliance is encouraged.

A lease shall be classified and accounted for as a capital lease if it meets one or more of the following four criteria:

1. The lease transfers ownership of the property to the lessee by the end of the lease term; or

2. The lease contains a bargain purchase option; or

3. The lease term is equal to 75 percent or more of the estimated economic life of the leased property; or

4. The present value at the beginning of the lease term of the minimum lease payments, excluding that portion of the payments representing executory costs to be paid by the lessor, equals or exceeds 90 percent of the excess of the fair value of the leased property to the lessor at the inception of the lease over any related investment tax credit retained and expected to be realized by the lessor. The lessee computes the present value of the minimum lease payments using the lower of the interest rate implicit in the lease, if known, or the incremental borrowing rate of the lessee.

If the lease does not meet any of these criteria, it would be classified and accounted for as an operating lease. In addition, there are certain disclosure requirements for both capital leases and operating leases under the Statement.

The following information would be disclosed in the lessee's financial statements or the footnotes thereto:

CAPITAL LEASES

1. The gross amount of assets recorded under capital leases as of the date of each balance sheet presented by major classes according to their nature or function. The total amount of accumulated amortization also shall be disclosed.
2. Future minimum lease payments as of the date of the latest balance sheet presented, in the aggregate and for each of the five succeeding fiscal years, with separate deductions from the total for the amount representing executory costs included in the minimum lease payments and for the amount of the imputed interest necessary to reduce the net minimum lease payments to present value.
3. The total of minimum sublease rentals to be received in the future under noncancelable subleases as of the date of the latest balance sheet presented.
4. Total contingent rentals (rentals on which the amounts are dependent on some factor other than the passage of time) actually incurred for each period for which an income statement is presented.

OPERATING LEASES

For operating leases having initial or remaining noncancelable lease terms in excess of one year:

1. Future minimum rental payments required as of the date of the latest balance sheet presented, in the aggregate and for each of the five succeeding fiscal years.
2. The total of minimum rentals to be received in the future under noncancelable subleases as of the date of the latest balance sheet presented.

ALL OPERATING LEASES

For all operating leases: rental expense for each period for which an income statement is presented, with separate amounts for minimum rentals, contingent rentals, and sublease rentals. Rental payments under leases with terms of a month or less that were not renewed need not be included.

ALL LEASES

For all leases: a general description of the lessee's leasing arrangements including, but not limited to, the following:

1. The basis on which contingent rental payments are determined.
2. The existence and terms of renewal or purchase options and excalation clauses.
3. Restrictions imposed by lease agreements, such as those concerning dividends, additional debt, and further leasing.

PROJECT AND OTHER SPECIAL FINANCINGS

Newton I. Waldman, Esq.
Vice President
M & W Resources Division

The purpose of this paper is to make you aware of what certain lectric utilities have done to finance their nuclear fuel and contruction requirements other than by traditional utility methods.

When the term "traditional utility methods" is used, it refers o the use of short term debt and internally generated funds to meet aily construction and operating cost requirements, which are subseuently retired with the proceeds of equity and long term bonded ndebtedness offerings.

In order to logically review the financing of nuclear fuel, we hould determine what nuclear fuel is and what makes it different.

Nuclear fuel requires a long processing time. From uranium exraction through the mining, milling, conversion, enrichment, and abrication stages of this process, utilities are required to pay not nly as processing occurs, but also, in some instances, to prepay harges several years prior to the time the services are actually renered. This is not the case with fossil fuels, which are usually paid or on delivery, or just prior to shipment from the mine or refinery.

Nuclear fuel is not readily marketable after it reaches a certain tage of processing, because the enrichment and fuel design are done ith a specific reactor in mind; and, because of this, it does not ormally offer an opportunity for resale to another utility. Thus, he cost of any delays in utilization must be borne by the utility.

Nuclear fuel has a longer useful life than fossil fuel. Fossil uel is instantaneously consumed; nuclear fuel is not, and <u>may</u> have a ife in excess of seven years. Nuclear fuel is a depreciable asset; ossil fuel is not. In addition, nuclear fuel may have a considerable esidual value when and if commercial reprocessing becomes a feasible ommercial enterprise.

The initial dollar investment in nuclear fuel is very high relaive to the small initial expenditures in fossil fuel necessary to ring a plant of similar size on line. These large expenditures, oupled with the long lead times required prior to the time when reacor fuel actually becomes productive in the power generation process, reates a financial burden on the utility not incurred when dealing ith fossil fuels.

Since 1970, more than 20 utilities have put in place nuclear fuel inancings totaling more than $4 billion.

While there are various methods of financing nuclear fuel, we will ook at the nuclear fuel leasing concept which has been employed in a ajority of cases.

I. Structure

The nuclear fuel lease arrangement is implemented by the formation of a third-party Entity (a trust or special purpose corporation) which will purchase the utility's nuclear fuel and will make all future payments for additional fuel and related services.

The utility will retain control in respect to all matters other than the making of payments and the holding of title to the nuclear fuel.

The Entity and the utility will enter into a lease which will require payments based on actual fuel usage.

The Entity will be funded through a credit agreement with lenders, which will be granted a security interest in the lease payments. In some arrangements, the Entity may lend surplus funds directly to the utility through an excess borrowing provision. Generally, the credit agreement runs from three to five years, with automatic annual extensions, and is structured so that commercial paper may be issued in the name of the Entity without a direct guaranty of the utility.

It is important to note that the utility is under an obligation to "take or pay" for the heat, whether or not any heat produced is actually used, by the utility, for the generation of electricity. If heat is not used, after certain prior contracted-for extentions have elapsed, the utility still has the obligation of liquidating the Entity's debts by purchasing the Entity's nuclear fuel or its rights to such fuel.

II. Accounting Considerations

The utility must determine the financial statement presentation it finds most beneficial. The company must keep in mind the fact that the lease concept is a financing and not a lease for tax purposes.

Under FASB 13, leases are classified as either operating leases or capital leases. Capital leases are reflected on the balance sheet, while operating leases are not. If a regulatory commission treats a lease with a utility as lessee as an operating lease for ratemaking purposes, which, under FASB 13, would be classified as a capital lease, the utility may treat such lease as an operating lease for financial reporting purposes. This is permitted by the Addendum to Accounting Principles Board Opinion No. 2 and requires only footnote disclosure.

III. Tax Implications

There are two key aspects of tax treatment relative to the leasing of nuclear fuel which should be reviewed: first, the taxable consequences of the sale of the nuclear fuel and contract rights relating to fuel processing and the sale or leaseback of that fuel to the utility; and, second, the tax treatment of a financing versus an operating lease.

A substantial line of authority holds that transactions which, in structure, involve a sale and leaseback, or sale and repurchase, of property will be treated as a financing arrangement for tax purposes. Where the seller, despite having transferred legal title to the fuel, retains the benefits and burdens of ownership and the Entity basically stands in the shoes of a lender, the transaction is not a sale but is in the nature of a mortgage.

Under a lease, the utility (lessee) treats the property as if it were owned by the utility itself. It depreciates the property, takes the Investment Tax Credit (ITC), and deducts the interest portion of the "payments" for tax purposes.

In transactions where the interest costs are being capitalized by the Entity prior to the insertion of fuel into the reactor, the utility may elect to deduct the current portion of the interest being capitalized for tax purposes; however, it will be required to report the corresponding AFUDC and interest expense for financial reporting purposes.

Under an operating lease, the utility deducts the lease payments (which substantially track the depreciation rate on a "units of production" basis) and takes the ITC under a lessor's election. The lessee (utility) is responsible for the payment of all taxes incurred by the Entity, with the exception of any taxes on income resulting from the payment of the Entity's management fee.

Nuclear fuel leases are structured to completely avoid or substantially minimize any adverse tax impact.

IV. Advantages

The preceding outline may be of academic interest, but, unless the utility can reap substantial benefits from the described transaction, there would be no point in taking on the burdens in time, money and personnel required to implement a nuclear fuel lease arrangement.

There are, however, obvious advantages. They are fourfold.

First, the utility will enjoy advantageous accounting treatment, in that the characterization of the transaction as a lease by its regulators will result in "off-balance sheet" treatment.

This in itself is not of primary importance until you analyze the outcome of this position.

Second, because the transaction is not on the balance sheet as a debt, no corresponding equity must be sold to maintain debt/equity ratios.

Third, the transaction is financed by the Entity using 100% debt, which is traditionally less expensive than a debt/equity composite cost, which would be necessary if the utility financed the nuclear fuel itself.

Fourth, the utility obtains through the Entity, by use of the excess borrowing provision, short term borrowing rates with long term accounting treatment, which results in a positive impact on the AFUDC rate.

Project construction financing within the electric utility industry has been used with increasing frequency in recent years. Project construction financing enables the utility to have precommitted the necessary funds to complete all or a part of a particular project. The assets to be financed are held in a separate Entity (either a trust or special-purpose corporation) which becomes the obligor of the project debt. This approach is similar to that employed when financing nuclear fuel.

I. Structure

A project construction financing is implemented by the formation of a third-party Entity which will hold title to the project assets until the project is completed or until a date certain, whichever is first to occur.

Due to the variations of bond indenture provisions, capital requirements, credit strength, and regulatory environment, the structure of individual project construction financings may vary from utility to utility.

The Entity will enter into a contractual arrangement with the utility whereby the utility agrees to borrow, from a group or groups of lenders, sufficient funds to construct the project. The utility, at its own option, or as required by lenders, can contribute equity or loans to the Entity to supplement or support the direct borrowings. The Entity can be structured so that temporary surplus funds can be loaned to the utility.

The credit arrangements for the Entity may include intermediate term taxable and tax-exempt (pollution control) debt, taxable and tax-exempt bank debt, Eurodollar loans, and commercial paper borrowings. Often, the credit agreements permit a term payout (three to five years) after completion of the project. This enables the utility to pay for the project by going to the debt and equity markets at the most propitious time.

Third-party ownership of a utility plant is becoming more commonplace. This is primarily due to the fact that some utilities cannot currently use the federal income tax benefits associated with direct ownership of the facility. The tax oriented leverage lease provides the mechanism for the utility to enjoy the effect of the tax benefits through lower effective financing costs. A project construction financing facilitates the implementation of a leveraged lease.

II. Accounting Considerations

The treatment for accounting purposes of a specific project construction financing is determined by the utility and its public accountants, taking into consideration the circumstances surrounding the specific financing.

However, the Securities and Exchange Commission (SEC), in Staff Accounting Bulletin No. 28, does provide some specific guidance:

"The balance sheet of an electric utility company using a construction intermediary to finance construction should include the intermediary's work in process in the appropriate caption under utility plant. The related debt should be included in long-term liabilities and disclosed either on the balance sheet or in a note. Capitalized interest included as part of an intermediary's construction work in progress on the balance sheet should be recognized on the current income statement as interest expense with a corresponding offset to allowance for borrowed funds used during construction."

Although the interest expense incurred by the Entity is included within the SEC's interest coverage calculation, it is generally not included in the utility's mortgage bond indenture interest coverage calculations.

In the case where the utility wishes to lease the project assets from a third party, the accounting treatment may differ. Under FASB 13, leases are classified as either operating leases or capital leases. (See prior discussion under Nucelar Fuel Leasing II.)

III. Tax Considerations

Any form of project construction financing, which involves transfer of title to a project asset during or after construction and operation, must include careful consideration of sales tax and other possible costs involved in any transfer of title. In addition, for a program in which ownership by someone other than a utility is contemplated, consideration should be given to whether the utility itself would be exempt from or subject to lower sales, property or other taxes than, for example, a leverage lessor or other owner would be.

The utility may take progressive investment tax credit and interest expense deductions for tax purposes on a current basis.

IV. Advantages

I am sure it will come as no surprise to you that there are advantages to the project construction financing approach. There are, to be precise, nine.

First, it provides low cost financing, in that short term debt is traditionally less expensive than long term debt.

Second, the precommitment of funds for part or all of the project is an obvious advantage, as well as a source of comfort to the finance department.

Third, ownership of the project by a third-party facilitates sale or transfer of all or a portion of the project without requiring a release of property from the lien of the mortgage.

Fourth, the transfer of property (portions of the project) during construction to the utility for use as bondable property to raise capital by the issuance of long term bonds.

Fifth, permits orderly public long term debt issuance, which results in better market receptivity and lower debt issuance costs, if a utility has peaks and valleys in the size of its year-to-year debt issues.

Sixth, it facilitates the use of a leveraged lease as a form of permanent financing.

Seventh, it reduces reliance on short term debt to fund a permanent portion of construction requirements.

Eighth, it may provide access to various sources of funds not normally utilized by utilities.

Ninth, it permits flexibility in the timing of issuance of preferred and common stock, since long term debt issues are more evenly spaced.

V. Regulatory Attitudes

The concepts of nuclear fuel financing and project construction financing seem to offer many utilities, caught between intense expansion requirements and shrinking capital markets, a viable alternative to traditional financing. But, what are the attitudes of their regulatory commissions? They love it.

The reasons are twofold. First, these third-party concepts are usually less expensive than traditional means of financing; therefore, the rate payer obtains a decided benefit reflected by a lower utility cost of operation. This is consistent with the utility's goal to provide the lowest cost of power to customers in its service area.

Second, the regulators love third-party financings because, for each dollar financed by use of this mechanism, that is a dollar less of rate relief that the utility has to ask for. It pulls the regulators' feet from the fire. It delays or defers rate increase decisions. It proves to the regulators that the utility is trying to keep costs down.

Conclusion

The methods of financing nuclear fuel and construction projects are not the only methods that have been or will be employed to solve part of a utility capital requirement.

They are merely examples of what some utilities have done to alleviate the pressure of continual needs for funds.

It behooves utilities to explore the benefits of third-party financing, and it behooves its regulators to give fair, speedy, and intelligent approval of such approaches whenever the needs of the utility and its rate payer will be served.

SEVENTEENTH SESSION, Thursday, May 22 - 1:15 p.m.

Concurrent Session G-2

MEASURED SERVICE

CHAIRMAN: Hon. Charles G. Stalon, Commissioner
Illinois Commerce Commission

SPEAKERS: Lawrence Garfinkel, Director-
Rates & Tariffs
American Telephone and Telegraph Co.

David C. Sweet, Dean
College of Urban Affairs
Cleveland State University

PARADOXES OF LOCAL MEASURED SERVICE

Charles G. Stalon
Commissioner
Illinois Commerce Commission

One of my favorite diversions is western movies, especially late at night when I want my brain numbed. Recently, while contemplating some of my problems as a regulator of telephone utilities, a scene from an old western movie came to mind.

It is a common scene: the wagons are in a circle, the Indians are circling the wagons and attacking with war whoops and flaming arrows, the women are screaming, the children are crying and the wagon train men are firing. In the midst of this clamor and chaos, inside one of the covered wagons, a doctor is calmly and deliberately assisting the delivery of a baby.

Now, in most movies of that type I identify with the hero, be he John Wayne, Gary Cooper, or Randolph Scott, but as I mentally replayed that scene I found myself identifying with the doctor. He seemed to carry my circumstances better and he exhibited the behavior I felt I would like to emulate.

In the real world of today's telephone industry, the FCC cannons, the Justice Department artillery, the slings and arrows of the courts, and the misfires of Congress are creating a terrific clamor. It is difficult for those of us in and about the industry who feel we are trying to aid the birth of new policies and practices in the telephone utilities to retain our sense of direction and speed in this clamor.

Today we have for our topic one of the more sensitive, and I believe sensible, proposals for repricing local exchange services, that is, briefly titled, local measured service (LMS).

Local measured service is, as we all know, not exactly a new idea. Versions of it have been around for decades. What is new however, is the economic, regulatory, and technological context in which this old idea is being re-evaluated.

Local measured service increasingly appears as if it is truly an idea whose time has come. In fact, it is rapidly becoming the "conventional wisdom" for local exchange pricing.

As usual in such attitude shifts, the shifts in practice lag substantially behind the shifts in attitudes.

Still, I think it is fair to assert that the intellectual debate today in the telephone industry is beginning to look like the debate in other utilities, water utilities for example. That is, the general rule is that usage should be metered. The remaining, and very interesting, debates are about the extent and nature of the exceptions. That, however, leaves a giant area for debate.

Before I introduce our main speakers for this afternoon, I want to discuss briefly two paradoxes of the current movement towards local measured service. The significance of these paradoxes is uncertain. They may be like a fly in the soup, bothersome only to the finicky. Still, they merit recognition and evaluation.

Before I state the paradoxes, however, I want to provide a background, i.e., a context, for the paradoxes. To accomplish this purpose I want to present a brief five point summary of the key characteristics of the coming transformation as I currently would like to see it happen.

First, the continuous growth of the large metropolitan areas and the increasing size of "local" exchanges make it imperative that some form of LMS be quickly imposed in all of those areas. This is an old lesson, and I insert it here for the sake of completeness and to draw your attention to an obvious point, namely, an attempt to maintain flat rates in such growing areas would make telephone access unnecessarily expensive for the overwhelming majority of customers.

At a bare minimum, charges per call and charges which vary with the duration of the call are necessary. Charges which vary with the distance between the parties are very desirable.

Second, available technology has so lowered the cost of metering local exchange calls that the appropriate goal should now be universal, mandatory, time-differentiated local exchange rates; that is, rates which vary according to the time of day and week, the duration of the call and the distance between the parties. This point I want to return to shortly, because I want to emphasize that universal LMS does not preclude a zero price on usage during certain periods for certain users, e.g., midnight to six a.m.

Third, available and forecasted technologies of local exchange users, primarily intracomputer uses, make it imperative that local exchange rates in the large and middle sized cities of this nation be transformed to measured rates rather quickly, that is, before strong interests develop which depend upon flat rates.

Fourth, since many present offices do not now have the electronic switching systems which make metering efficient, and the rewards for such metering cannot justify replacing that equipment merely to obtain LMS, it follows that some exchanges will probably be flat rate priced for many more years.

Fifth, it follows from the preceding four observations that some of the administrative expendiencies adopted by commissions in the past, such as uniform state-wide pricing for a multi-exchange company, will have to be abandoned. Commissions will have to adopt exchange by exchange pricing. The burden of such pricing policies will require great improvements in the regulatory decision process.

With these conjectures about the future as background, let me turn to my first paradox; I'll call it the paradox of inertia. For years it has been argued in the economics profession that local exchange calls should be priced to reflect the marginal cost of making these calls. The logic of the economics of welfare which justifies this conclusion is well known and I won't repeat it. I merely want to emphasize that that theory is as critical of overpricing as it is of underpricing. It would be a serious mistake to move from significantly underpricing message units to overpricing them.

That conclusion brings me to my first paradox. Economists argued for so long for pricing usage, and were rebutted so long, partially by the argument that metering was expensive, that when technological change lowered the cost of metering dramatically they redoubled their efforts to gain LMS. The logic of their arguments implied that the lower the cost of metering, ceteris paribus, the stronger the case is for metering.

On the other hand, I am somewhat concerned that many proponents of LMS overlooked the fact that the same technological changes which dramatically lowered the cost of metering also lowered the marginal cost of a local call, thereby reducing the force of arguments for metering.

Some of the estimates I have received from Illinois Commerce Commission economists and engineers, estimates which they are not yet ready to state and defend publicly, indicate a surprisingly low, to me at least, on-peak marginal cost for a mean length call. Obviously, off-peak rates are near zero.

One generalization which seems highly likely to be correct is the following: Most if not all LMS so far in place in Illinois has significantly overpriced message units. A second generalization which appears increasingly attractive is that zero priced message units are defensible during off-peak periods in many exchanges.

The second paradox I want to mention today is also the result of the interplay of the existing and developing technology and economic welfare theory. The same technology which is lowering the marginal cost of a call is also lowering the marginal cost of access in many exchanges, especially small exchanges.

This proposition not only supports an argument for de-averaging access charges over exchanges, it also suggest the possibility that a welfare argument for subsidies for access in small exchanges may be even better supported than in the past.

Let me close my remarks with one obvious deduction from my previous remarks, namely, the need for greatly improved cost of service studies in the telephone industry. I believe that cost-of-service studies (COSs) must assume great importance as aids to rate setting in local exchanges as we move to LMS. My principal concern with COSs, especially those done in the telephone industry, is their tendency to encourage the fallacy of reification, that is, to encourage non-professionals to accept the belief that the average cost of providing a jointly produced local service is an objective, measurable concept.

Since economic theory makes it clear that the allocation of joint costs of jointly produced services is a purposeful activity, COSs can only be evaluated according to their usefulness. Consequently, they should never be described as "correct" or "incorrect", but only as more or less useful. Like prescription medicine they should always come labeled with directions for use and with warnings about harmful side effects and the dangers of misuse.

First, it is obvious that if we are to set time-differentiated local rates in pursuit of Pareto pricing goals, we need to make use of time-differentiated marginal cost estimates. Such cost estimates must recognize an allocation of joint costs among the chosen segments of the day and week, and they must help us define the segments.

Second, we must have cost allocation studies of a more controversial type; those which allocate local exchange costs between intra and inter exchange services and which allocate company wide overhead among local exchanges. These allocations will influence the inter-period, intra-exchange pricing structure. If these studies are to be understood, their purposes must be known. If the purposes of the interexchange allocation studies conflict with the purposes of the intraexchange ones, the possibility of a rational pricing policy will be reduced.

After decades of setting rates on ill-defined value of service principles which de-emphasized the role of cost, marginal costs or costs of any type, in determining rates, it is only reasonable to expect that few commissions are staffed or otherwise competent to make or evaluate time-differentiated marginal cost studies or demand elasticity estimates. From this base commissions must move to sophisticated economic and cost analyses in a few short years. They must do this not only to implement increasingly sophisticated LMS systems, but also to react to increasing competition in terminal equipment and interexchange communications. After decades of regulating with a model which considered only the direct effects of commission actions, they are now being asked to accept one which emphasizes secondary, tertiary and systemic effects. Without mastering freshman economics they must now move into graduate work.

In summary, the demands for increased competence from commissions is accelerating rapidly, and the transition to LMS makes up only a part of that demand. If commissions are to respond to these demands constructively, it will be necessary for the telephone utilities to expand their research efforts in these rapidly changing areas. Few commissions will be financed adequately to take the lead in such research. The industry must resist the temptation to devote its research budgets to the newly competitive areas at the expense of the less immediately threatened local exchange systems.

MEASURED SERVICE - THE INDUSTRY VIEW

Lawrence Garfinkel
Assistant Vice President
AT&T Company

Dr. Stalon's opening remarks about the cannon booming, the artillery moving up, and the slings and arrows of outrageous fortune made me feel right at home. Nevertheless, as a representative of the beleaguered telephone industry, I want to assure you that this is not Custer's last stand. We will survive, somehow. But the future success of the industry depends, in my judgement, on the prompt introduction of local Measured Service. The more competitive our marketplace becomes, the more we need cost-based, usage-sensitive rate structures.

Having been involved in local service pricing for nearly eight years, first in an operating company and then at AT&T, I've seen the business change a great deal. The basic guiding principle, however, has remained unchanged: universal service must be preserved. By universal service I mean the provision of access to the telephone network in a form that the majority of Americans find practical and affordable. To be sure, the maintenance of universal service will redistribute the cost of telephone service in ways that may be painful for some people. But that is an unavoidable part of the transformation in the industry today, the necessity of which is heightened by the impact of external forces on the business.

Separations procedures are changing and I am certain this will have a major impact on the price of a local phone call. The expensing of station connection charges, which some of you are familiar with, also has consequences for the pricing of local exchange service. The business environment mandated by the Federal Communications Commission, and in some cases by the state regulatory commissions, will affect the industry's ability to sustain telephone service as we have known it in the future. Those are some of our basic, underlying motives for introducing Measured Service.

In the limited time available, I cannot cover the subject of Measured Service completely. But I can explain to you the basic outlines of our situation. I want to show you what we in the Bell System envision as the Measured Service plan. I'll explain some of the reasons for it, such as the effects of separations and inflation. Finally, I'll show you how people actually use the telephone and how their habits of telephone use relate to the kind of rate structure that is needed.

So let's just start with the plan itself. Basically the Measured Service plan, as we envision it, has two underlying goals. We intend to unbundle local usage charges from the charge for access to the telephone network and then to price local usage above cost so that it will provide a contribution. Under traditional flat-rate pricing, customers have paid a single fee that covers both access and unlimited local usage, but for reasons I will explain in a moment, flat-rate local service can no longer be priced at a universally affordable level. Access to the telephone network is, however, a critical necessity for almost everyone in modern society, indeed in emergencies it can be a matter of life and death. We must therefore guarantee that access will be available at an affordable price. So unbundling network access is the crucial change because it is the key to the perpetuation of universal service.

We plan to price local usage so that, at minimum, its price will be equal to marginal cost. If possible, local usage should not only cover the costs it incurrs, but also provide a contribution. Residential measured access would be the benefitted service; that is, it would be priced below cost to ensure that everyone can afford it. Thus we can replace the contribution currently flowing to local service from inter-city toll traffic through the separations procedures. That contribution is now being constrained and, we expect, it will ultimately be eliminated.

The price of local usage under Measured Service will be cost-related in the sense that we will charge according to the number of a customer's calls, their duration, distance, and time of day. Time-of-day charging is appropriate because calls made during periods of the day when the network is relatively crowded are more costly. Of course, usage charges will only apply to outgoing calls. Notice that this four-element charging schedule for local usage is quite similar to the way we charge for toll calls today. Customers sometimes find usage-sensitive charging for local service complex and confusing because they are accustomed to the old, simple flat-rate structure. But, in fact, they have traditionally paid for toll calls on this same basis for nearly a hundred years.

We propose to offer residential telephone users a choice among three local service options: standard measured service, low-use measured service, and a premium flat-rate service. The first two options will incorporate the four-element, usage-sensitive charging structure I just described. Standard measured service, which will include a usage allowance, will for the majority of its subscribers roughly correspond in terms of price to current flat-rate service. So customers who select standard measured service will see no significant change in their bills, at least initially. We intend low-use measured service, which will have little or no usage allowance, to serve as a threshold option. It is the vehicle by which we hope to maintain universal service at the level of development we have achieved in the United States, which is around ninety-six percent of the households. Low-use measured service will be priced well below standard measured service and the remaining flat-rate service. Thus, it will become the entry-level service that assures access to the local and toll network.

Notice that we are not talking about withdrawing flat-rate residential local service. The goal is a flat-rate option for residential customers that, in essence, pays its own way. By virture of the fact that it allows for unlimited calling, it will be priced at a premium level. Service of this nature exists today. Those of you from Illinois are probably familiar with the flat-rate service currently offered in the Chicago metropolitan calling area, which is priced between $25 and $30. That price level, however, will not be generally charged for flat-rate service during the initial transition, because we plan no dramatic discontinuities from the current schedule as we introduce the concept of Measured Service.

Having described the Measured Service plan, I want now to explain the reasons for the innovation. Basically, inflationary pressures and growing competition make local Measured Service a necessity; while the ways it improves equity among customers and the telephone company's marketing opportunities make it desirable. There are many other reasons that I won't cover, but these four are the most important.

We expect the impact of inflation on our industry to be a compounding problem. This year it exceeds ten percent and we doubt it will drop below seven percent in the foreseeable future. I don't have to explain to this audience that any utility, including the telephone company, is a capital intensive industry with a characteristic and growing appetite for capital. In the Bell System, the construction program this year exceeds $16 billion. Both growing calling rates, which drive up the need for new construction, and inflationary pressures force us to return again and again to state utility commissions for rate increases, which I'm sure you've all heard about before.

The second reason local Measured Service has become a necessity today derives from the growth of competition in the telecommunications industry, which will diminish the contributions that have sustained basic telephone service at the rate levels we are familiar with today. Tomorrow, the situation will be radically transformed. There's no doubt about it. If you look at the House bill or the Senate bills, intended to amend the Communications Act of 1934, you will see that they are meant to foster competition and that separations procedures are therefore treated in a new way. The ultimate conclusion is that in the future toll-traffic pricing will be cost-based. When that happens, the contribution that now flows to local service from interstate and intrastate message toll services will tend to decrease over time and may, ultimately, disappear.

But usage-sensitive local service pricing is not only a necessity forced upon us by economic constraints, it is also an innovation that we should welcome because the introduction of Measured Service will constitute a major improvement in the equity with which the costs of local service are distributed among telephone users. This is the third reason for Measured Service. There are wide disparities in the ways different people use the telephone and, consequently, in the costs they cause to the network. Under flat-rate pricing, costs are averaged and all subscribers must bear the burden imposed by heavy users. Under Measured Service pricing, each customer's bill reflects the cost of the use he makes of the telephone.

I doubt anyone would quarrel with the principle that individual's should pay for telephone service in proportion to the costs that their use of the telephone cause. This is a logical, intellectually acceptable principle. Of course, some heavy users tend to forget the logic of equity and become emotional during actual implementations of Measured Service, when they discover that equity requires they pay more for their local service. Commissioner Sweet has described how shortsighted emotional considerations appeared in the Ohio proceedings and, I expect, special interest groups will introduce them elsewhere. But we must not allow the principle of equity to be pushed aside for it is utlimately in the best interest of society as a whole. In a moment I'll show you some of the characteristic patterns in the distribution of local usage which make clear the size of the sacrifice in distributive justice that would be involved in the perpetuation of non-optional flat-rate pricing.

Not only will usage-sensitive rate structures improve equity among customers, they will also give customers more freedom to control the level of their local service bills. A customer will be able to tailor his bill to his needs by restricting his discretionary use of the network and by taking advantage of time-of-day discounts on the price of local calls. To the extent that customers conserve and avoid calling during periods when the network is crowded, the need for investments in a new facilities is reduced and the revenue requirements of the telephone company are correspondingly diminished.

Finally, Measured Service will allow the telephone company to take advantage of the marketing opportunities presented by the growing number of new uses for the telecommunications network. Conversely, we may encounter significant marketing costs if a usage-sensitive price structure is not in place when unlimited competition takes over in the intercity market.

Those, then, are the main reasons for the introduction of Measured Service. Every one of them is arguably a sufficient reason, by itself, for transforming the way that we price local telephone service. But the point I want to drive home, above all else, is the significance of the impending Federal legislation. The legislation is complex, but it ultimately implies that the loss of contribution from toll and vertical services, which are already becoming more and more competitive, will be accentuated. This will undermine universal service unless we unbundle access to the network from local usage.

Figure 1 gives a quantitative picture of the dimensions of the problem. The graph on the left shows how the average price of flat-rate local service would have to rise over the next decade if we take into account only the effects of inflation and rising costs caused by rising usage. In 1989, the average price of residential service, which is $9.20 today, would be $16.60. That's about an eighty percent increase. Actually, even these figures are optimistic because the left-hand graph presumes a continuing contribution flow from vertical, competitive services. The impending legislation requires, however, that any unregulated, competitive AT&T subsidiary be a fully separated entity so it could not help to sustain local service.

If the left-hand graph is disturbing, the one on the right is a nightmare. It depicts the effects in 1989 of decreases in the contribution from separations procedures. That contribution to local service is approximately $5 billion today, and we estimate it would be about $20 billion in 1989. These numbers were all part of the exhibits we submitted to the Federal Communications Commission in Docket 78-72. Actually, the intrastate toll schedules, which mirror the interstate schedules, provide an additional contribution to local service of roughly $10 billion. If the contributions from both these sources were to drop to zero by 1989, which is being discussed very seriously, then the entire $30 billion burden would have to be borne by the local exchange user.

As the right-hand graph shows, the loss of the interstate toll contribution alone would mean an average residential flat-rate local bill in 1989 of roughly $35. In other words, the average flat-rate would treble. This projection has frailties, not the least of which is that, as a society, we simply cannot allow this nightmare to come to life. Still, as an exercise, it is invaluable because it shows what the future will hold for the local exchange user unless alternatives are developed. That is why we consider the transformation to Measured Service so crucial.

If Measured Service were introduced today, when the average residential flat-rate is $9.20, an ideal rate structure would look something like Table I.

TABLE I

1979 MEASURED SERVICE RESIDENTIAL TARIFF
(NO LOSS OF SEPARATIONS SUPPORT)

Average Rate	$9.20
Premium Flat Rate	$9.80
Standard Measured	7.00
Allowance	4.00
Low Use Measured	5.00
Allowance	0.00
Initial Minute	.04
Each Additional Minute	.01

The Toll Time-of-Day Discount Schedule Applies to Usage

We estimate about twenty-six percent of the customers would choose one of the two measured options in this tariff.

As I said before, today's $9.20 average residential flat rate would have to rise to about $35 in 1989 to cover inflation, rising costs, and the total loss of separations revenue. Under those circumstances, the prices in a measured tariff structure would look something like those in Table II.

TABLE II

HYPOTHETICAL 1989 MEASURED SERVICE RESIDENTIAL TARIFF
(TOTAL LOSS OF SEPARATIONS SUPPORT)

Average Rate	$34.85
Premium Flat Rate	80.00
Standard Measured	20.00
Allowance	6.50
Low Use Measured	14.00
Allowance	0.00
Initial Minute	.09
Each Additional Minute	.03

The Toll Time-of-Day Discount Schedule Applies to Usage

A premium flat rate option in the range of $80 may seem impossible, but even at that price, ten percent of our residential customers make such heavy use of the local network that they could benefit by selecting the flat-rate option. I should emphasize that the tariff depicted in Table II is hypothetical; it is only a rough guess intended for illustrative purposes.

Remember what a world where the average local exchange rate approaches $35 would mean if there were no alternatives to flat-rate service. If we simply continue to escalate the flat rate during the next decade, customers are going to be driven out of the market. We know that; we have studies to prove it. The study National Economic Research Associates did for us, for example, makes it perfectly clear. People who have a limited ability to pay for telephone service simply could not afford a mandatory flat rate of $35.

Now I would like, as I promised initially, to sketch for you some of what we have discovered about how people actually use their telephones. This information and the figures I will use were derived from a careful statistical study of seventy-nine residential offices all over the country done by Bell Laboratories, which is available to anyone who wants it.[1]

Figure 2 shows how telephone usage is distributed among residential customers, and it allows some striking conclusions. About sixty-one percent of the residential users make less than 3.85 calls a day, which is the average calling rate. Half the customers make about seventy-nine percent of the calls; while only twenty percent make about forty-five percent of the calls. At the other end of the usage spectrum, twenty percent of the customers make only about five percent of the calls. Indeed, thirteen percent make one call a day or less. So it is fair to say that the fifth of the customers who call the most use the telephone nearly ten times as much as the fifth who call the least.

That is a common characteristic of usage in local exchanges. This distribution of usage has held true in every study we have seen, and we have done a number throughout the country. Of course, the average calling rate may vary in different localities, but the shape of the usage-distribution curve is always almost the same.

The distribution of telephone usage is similarly skewed among our business customers. About six and a half percent of them make one call a day or less. Conversely, five percent of the business customers make about sixteen percent of the calls; while ten percent make about twenty-six percent of the calls. The average calling rate of business customers is 7.04 calls per day, but about fifty-nine percent call less than that.

Figure 2 is thus a graphic picture of the magnitude of the equity considerations at issue in local service pricing and of the distributive injustice inherent in flat-rate pricing structures. There is no question that under flat-rates, even within a single class of service, some users are forced to subsidize the local telephone service of other users.

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1. Carl Pavarini, "The Effect of Flat-to-Measured Rate Conversions on Local Telephone Usage", in Pricing in Regulated Industries: Theory and Application II, ed. John T. Wenders (Denver Colorado: The Mountain States Telephone and Telegraph Company, 1979).

To return to a point made by former Commissioner Sweet and Commissioner Stalon, Measured Service will redistribute the cost of local service among users. If the local revenue requirement were held constant, about sixty percent of both residential and business subscribers would receive bills equal to or below their old flat-rate bills.

Let me show you another way the distribution of local usage among residential customers can be depicted. Each of the histogram bars in Figure 3 represents thirty calls a month. The average calling rate in this study group was a hundred and seventeen calls a month, but the median, which by definition half of the customers fall below, was only ninety-three. The wide disparity between the average and the median is one more measure of how strongly the distribution of usage is skewed. As the figure shows, there are quite a few customers who make heavy use of the telephone. Believe it or not, we have some who average six hundred calls a month. Whether they are actually business users disguised as residential customers, I don't know. But that, at least, is what empirical studies of usage in the residential class of service show.

There are also wide disparities in the duration of completed calls among residential customers, which can be seen in Figure 4. Here, each bar represents thirty seconds. Almost half of the calls last less than a minute. If, however, you ask customers, to estimate the average length of their calls, as we have done in several market research studies, they generally answer ten minutes or more. But, interestingly, Figure 4 shows that they are mistaken. People apparently tend to remember only their longer calls. They forget the short ones, such as commuting calls like, "Can you pick me up at the train station? Thanks. Good bye." That's a very quick call, but it's a local call nonetheless. Indeed, about eighty percent of local calls terminite within five minutes.

The last bar on the far right of the graph may be misleading because it aggregates all calls longer than twenty minutes. But the curve makes clear the basic negative exponential distribution characteristic of the duration of telephone conversations. Some customers make strikingly long calls. The longest call in this study lasted two hundred and seventeen minutes, which is over three and a half hours. Since it was made in an untimed area in California, it was billed as a single message unit. The granddaddy of all the calls we have recorded was between two unnamed university campuses in Manhattan on a computer facility: it lasted for eighty-two and a half days, incurring a single message unit charge of a little over eight cents. Such calls are exceptional, but more common than you might imagine.

Figure 5 shows how telephone calling is distributed across different periods of the day. With Measured Service, we can construct discount pricing schedules that take these patterns of usage into account. In an area where businesses predominate, their usage tends to determine the busy hour and the corresponding peak load requirements of the local office. The local residential profile must, however, be superimposed on the business profile to fully understand busy-period usage. If some of the residential traffic, for example, is discretionary and if the telephone company could price properly, then some of the traffic might shift, making the overall traffic profile more nearly level. This would lower peak-period costs, which play a major role in determining the cost of investments needed in central offices.

Local time-of-day profiles often show interesting valleys: for example, the noon-to-one period in Figure 5. We are currently planning a trial that may use the noon hour as an off-peak. But I don't want to mislead anyone; there are limitations to what can be accomplished with time-of-day pricing. In an office where residential customers predominate, they will determine the busy-period pattern. So we must carefully balance the discount schedule throughout the state to avoid counter-productive pricing signals in predominately residential exchanges.

In conclusion, let me return to some things I mentioned earlier. Everyone knows the local exchange network is not competitive today, but we would be foolish to think it will remain so. I can easily envision the day when the local network will be competitive. Competition will in all probability grow in this market in the same way it entered the intercity market -- through new technology and through the efforts of heavy users to exploit new technology in order to reduce their telecommunications expenses. Today, access to the local network is one of the most expensive components of the intercity services offered by competitors. There is no question in my mind, therefore, that in the future competitors will attempt to bypass the local network.

But in the meantime, traffic on the local network will continue to grow, generated both competitively and by the Bell System. Competition is proliferating, people in the computer business are daily discovering new services that can be offered for sale over the telephone lines, and the telephone company plans to create all kinds of new uses. Without usage-sensitive local rate structures, the cost of all this new usage would have to be distributed among all local customers, regardless of their individual levels of usage. Surely, that would be unfair, and it will become impractical as well when the contributions from other services to local service decrease.

So, from an industry point of view, looking at the future without a Measured Service rate structure in place is a disturbing vision that we really don't want to face. Consequently, there is going to be a lot of activity before the public utility commissions. But we have tried to learn from the bitter lessons former Commissioner Sweet described. We think the first job is to make Measured Service available to our customers. Then, in time, we can move to the ultimate schedule needed.

MEASURED SERVICE - THE OHIO EXPERIENCE

Dr. David C. Sweet

Dean, College of Urban Affairs
Cleveland State University

First of all, let me say that I am pleased to have the opportunity to speak at the Iowa State Regulatory Conference again this year, and to informally discuss the Ohio experience in dealing with measured telephone service.

The State of Ohio during the last decade has been very much in the midst of the turmoil surrounding measured service for telephone customers and the implementation of that service. I would refer to it, perhaps, as a hornet's nest. My purpose today is not to discuss the economics of the subject instead I'd like to talk about process -- the process of proposal, regulatory consideration and adoption of measured service. The process in Ohio has -- I believe -- constructively re-shaped the thinking of AT&T and other telephone companies as they consider the implementation of measured service. In Ohio, measured service implementation has traveled a rather rugged road and continues to have significant problems.

The chronology begins with two landmark rate case decisions by the Public Utilities Commission of Ohio (PUCO). The first case, filed in 1974 by Ohio Bell Telephone, requested a rate increase of $214 million which at that time was the largest rate case ever considered by the Ohio Commission. The second case was filed shortly thereafter by Cincinnati Bell Telephone.

The Ohio Bell case had four critical issues. The first was the company's request for mandatory measured service for business customers. The only Ohio business customers that had mandatory measured service at that time were in the Cleveland area, and this service for business customers dated back to 1918.

The second critical issue was the provision for optional residential measured service. Those who preferred measured service would be given a lower rate with a 15-call allowance, and a nine-cent charge per call beyond that. Third, a new directory assistance charge of 20 cents per call beyond a three-call allowance was requested. This feature was similar to the directory assistance charge adopted by the Ohio Commission in 1972, one of the first such charges in the country. Finally, Ohio Bell requested an increase on coin telephones from 10 to 20 cents.

The public hearings, beginning in November, 1975, and continuing to April, 1976, generated 11,500 pages of transcript. The case set many records in the commission's history: The longest hearing process (75 days), the largest group of intervenors, the first case to be deliberated under the state's newly enacted "sunshine" law, and the last case to be determined under the outgoing RCNLD (reconstruction cost new less depreciation) rate base law that had been replaced by an original cost statute.

At the public hearings, directory assistance charges were contested vehemently by the Communications Workers of America, who felt that such charges would have an adverse impact not only on the telephone industry, but certainly on its membership. During the commission deliberation at the conclusion of the hearings, the concept of directory assistance charging was adopted. I was overruled as the "consumer commissioner" in seeking to have directory assistance charges apply only to those numbers which appeared in the telephone directory. The three-call allowance was subsequently increased to five calls.

The residential measured service option led to some interesting "sunshine" debates. The company had called for a 15-call allowance, but this was opposed by senior citizens and others who indicated that it was not adequate. The company representative, on cross examination, admitted that the decision to go with 15 was arbitrary, but said Ohio Bell had contemplated the concept of a buddy-system where a senior citizen could use the phone on alternate days by linking up with other senior citizens.

The commissioners' debate in itself was an interesting "sunshine" activity, similar to a negotiation strategy. "On the table" so to speak were the key issues of a call allowance and the monthly base charge. I proposed a one dollar reduction in the flat rate charge and a 60-call allowance. I was countered by a more conservative colleague who went with the company proposal at 15 calls and the continuation of the current flat rate charge. To make a long story short, the ultimate determination was a concept of a 50 cent decrease from the flat rate level and a 30-call allowance. It truly was a negotiation session -- unfettered by major economic rationale. This was the first step in establishing a "lifeline" rate concept -- but on an optional basis.

Subsequently, in the Ohio General Assembly there was a great concern, as there now is in most state legislatures, about rising utility costs and their impact on low income and fixed income households. As a result, a bill was introduced to provide for a vendor line of credit system in which the winter heating costs of low income senior citizens would be reduced by 25 percent. This reduction would be subsidized by utility tax revenues from electric, gas, and telephone utilities. The telephone utilities successfully argued their case for exemption from that particular proposal because they already had a lifeline service rate in effect. I agree with the telephone companies that optional residential measured service with a very low base charge can be considered a lifeline program.

The third tariff item debated was the mandatory measured business service, which, as I said before, has been in effect since 1918 in the Cleveland calling area. This proposal was opposed by the retail merchants, the state universities, and many other intervenors. The commission adopted an 18-month, phased-in approach to meet the availability of metering equipment, an approach that led to an extreme amount of controversy in the courts about discrimination.

The Ohio Bell case provided the first set of forces in the process, with a series of customers, particularly business customers, concerned about mandatory measured service.

Some months later, Cincinnati Bell Telephone filed its case. Hearings began about six months after the conclusion of the Ohio Bell case. The request was for a four-element mandatory measured service. The company proposed to move toward full measured service on a mandatory basis in four central offices. The four elements were:: number of calls, distance, duration, and the time of day. Approximately a dozen intervenors came together and stipulated all issues in the case, including the tariff proposals for one exchange (the Hartwell office in this case) to be included in this experiment.

On March 9, 1977, the Ohio PUCO approved the stipulation and then the protests began. The Hartwell exchange of 8,000 people, 270 businesses, and 3500 dwellings banded together against measured rate service. They hired an attorney who, since 1977, has represented all of the opponents of the various plans I outlined.

The Hartwell citizens requested a rehearing, and, as the commission was considering a rehearing, the citizens' committee went to the Ohio Supreme Court. The Supreme Court in turn sent down an order on December 27, 1977, saying that the notice provided by the company regarding the designation of the Hartwell exchange was inadequate, and remanding the case back to the commission. Under the court order the narrow issue of whether the Hartwell exchange should be designated for the experiment was to be reviewed in a hearing, and the broader issue of whether measured service should be introduced anywhere within the Cincinnati Bell service area also was to be considered in a new hearing before the test could commence.

The political process also began to respond. A resolution was introduced into the Ohio General Assembly to prohibit the PUCO from approving any measured service until further study. A total of four bills were introduced to prohibit the adoption of measured service. The lead sponsor of the legislation was the chairman of the Senate finance committee, which, by the way, approves the PUCO budget.

In a series of negotiations, it was decided that the PUCO would ask the National Regulatory Research Institute (NRRI) at Ohio State University to study the economic impact of measured service. (This month, the NRRI released a report which deals with an aspect that was of great concern in Ohio: the impact of measured telephone rates on telephone usage by government and non-profit organizations.

Meanwhile, under an accord with the finance committee chairman, it was agreed that the General Assembly legislation would be deferred, thereby freeing the PUCO to further consider measured service.

In my testimony before the Ohio General Assembly at that time, I raised the following eight questions:

1) Should the Ohio General Assembly block cost-based pricing for utility service in Ohio?

2) Should telephone measured service be banned in Ohio because one telephone utility did a poor job of implementing it in one exchange of its service area?

3) Should a rate structure be banned in Ohio that would reduce monthly telephone bills for most business and residential

customers?

4) Should a rate structure be banned in Ohio that would insure that basic telephone service is affordable for all who need and want it over the next five to ten years?

5) Should a rate structure be banned in Ohio that would slow down the revolving PUCO door for larger and more frequent rate increase requests?

6) Should a rate structure be banned in Ohio that would benefit persons over 65 and those making less than $15,000 a year, at the most, and benefit others making over $25,000 a year at least?

7) Should the option of measured service rates be taken away from 200,000 customers, including those over 65 or those on low and moderate incomes who have already elected this optional measured service residential rate?

8) Should the General Assembly cancel the business measured service rate that has been in effect for 57 years in Cleveland and since 1976 in the Ohio Bell territory?

I pointed out the difficulty of arguing for rate structure reform in electric and gas utilities, as I had been doing on the Ohio PUCO and as had a number of reform-minded legislators, and then turning right around and opposing the same concept when applied to telephone utilities. Fortunately, the intellectual honesty of some of the legislators prevailed, and they saw the obvious conflict between promoting such things as time-of-use pricing in the electric field and opposing a similar concept in the telephone industry. (a copy of the testimony is attached)

On February 2, 1978, over the PUCO Telex machine, came the following press release from Cincinnati Bell Telephone: "Cincinnati Bell will not go through with the trial of measured rate service in the Hartwell area. Cincinnati Bell President Richard T. Dugan had this to say about dropping the trial: 'We have learned a lot since including the measured rate trial idea in our 1975 rate case filing. We thought the fairness of paying on the basis of what you use would appeal to all but highest telephone users. Obviously many people are still not convinced that the new measured rate service would benefit most customers!'" This partially defused the issue -- for at stake was a statewide legislative prohibition against measured service telephone rate structures.

The process did not end there. The Supreme Court had remanded the case, legislation was still under consideration. The bill being considered would have prohibited any telephone rate or charge based upon the number of local calls made, the time of day, the duration, the distance between customers. Had it been enacted, it would have tied the hands of the PUCO in terms of any measured service concept. The sponsoring senator, I might add, said that measured service was just another way to put taxpayers at a disadvantage, and that it runs counter to what Alexander Graham Bell invented the telephone for.

While putting together my testimony to go before the state legislature, I came across the fact that, in 1930 when new dial telephones were being installed in the nation's capitol, the United States Senate passed a resolution requiring a return to the old operator-assisted phones. Such congressional appreciation -- or lack of appreciation -- for new technology too often persists even today.

The kinds of political alliances that have been formed around this issue are intriguing. These alliances include the following: schools, which were required to come under the mandatory measured business service charging plan of Ohio Bell Telephone, as well as realtors and real estate agents. At one hearing, the school board people wore buttons saying, "Save Our Schools." They also filled a giant hearing room with opponents claiming that measured service would bankrupt the public school system in Ohio.

Much of the opposition was orchestrated by the high-use business interests, particularly the real estate industry. In terms of background politics, the test in Ohio turned out to be between the lobbyist for the real estate agents -- who thinks he's number one in the General Assembly -- and the chief lobbyist for the telephone industry. These two personalities were clearly clashing in this particular effort before the General Assembly.

The PUCO tried to further defuse what was obviously getting to be an unholy alliance, the alliance between the school "good guys," if you will -- who can be for bankrupting schools or who can oppose the public schools? -- and the real estate agents. The Commission put together a plan that essentially exempted the schools from the measured business rate. This trade-off was intended to scuttle the emerging alliance and scuttle the legislation. Unfortunately, what happened was that a whole new group -- the hospitals, the social service organizations, the museums, the county commissioners -- came before the PUCO and demanded equal treatment with the schools.

On January 11, 1980, the Supreme Court reversed the commission's Ohio Bell decision on Mandatory measured service and remanded it back to the commission for further hearings saying that there was not adequate notice. On January 14, the realtors requested the commission withdraw the mandatory measured business tariff. In its place, they asked for the flat-rate tariff that had been in effect during the conversions of the exchanges I mentioned earlier. On January 30, 1980, the commission denied the realtors' request and set an additional hearing for May 28. Following that came a petition for a writ of mandamus, an application for an alternate writ of mandamus, and a motion for rehearing on denial -- a lawyers paradise. At this point in time the issue still is unresolved -- but hope springs eternal.

What can we learn from all of this? I said at the beginning that I was not going to give an economic or academic approach to the marginal cost pricing aspects of measured service. What we can learn is that communications -- and here we're dealing with the communications industry -- have failed: communications with customers, with commissioners, and with legislators. Second, the process I have outlined supports one of Commissioner Stalon's earlier comments about the need to move towards universal measured service in an evolutionary rather than a revolutionary manner. Consumers are not prepared to accept radical changes. When radical changes occur, they move to the political process to stop the change. Finally, I think we need to better understand the political implications of these evolutionary changes that are being introduced.

I had on my wall a plaque which was to me, as a commissioner, a source of universal wisdom. It was a statement written by a Princeton law professor several decades ago. Professor Bernstein said: "The single most important characteristic of regulation by commission is the failure to grasp the need for political support and leadership for the success of regulation in the public interest." In the context of today's remarks, this simply means that if we are to move toward an evolutionary change in the adoption of a measured service alternative for pricing of telephone services, we are going to have to better understand and better communicate the implications of these changes -- or bear the consequences which emerge from the legislative process.

EIGHTEENTH SESSION, Thursday, May 22 - 1:15 p.m.

Concurrent Session G-3

STATE COMMISSION ATTITUDES ON DECOMMISSIONING

CHAIRMAN: John B. Gillett, Partner
Whitman, Requardt and Associates
Board of Directors, Iowa State Regulatory Conference

SPEAKERS: R. Thomas Sweatman
Director of Engineering
Texas Utilities Commission

Cliff Swedenburg, Chief Engineer
Minnesota Public Service Department

DECOMMISSIONING - A NEW WORD, AN OLD PROBLEM

R. T. Sweatman

Director of Engineering

Texas Public Utility Commission

The way in which nuclear power plants will be removed from service in the years to come is a subject of much debate and indecision at this time. The fact that no large commercial reactors have yet been retired is a major cause for uncertainty concerning final costs, public safety, and the appropriate technology. Also, there are no standardized regulations pertaining to removal in the code of Federal Regulations. At the present time there are three basic options which are being discussed: Mothballing, encapsulation and dismantling. Considerable time and effort has been and will be consumed in arguing which method is best. In reality it will probably be one or a combination of these or even other methods, but I hope that the utilities and the state regulators will be allowed the flexibility to utilize the safest, most desirable and least costly method. Since actual removal of a large commercial nuclear reactor from service is years in the future, we can only speculate as to the method to be used. One thing remains certain, however: there will be a significant cost associated with retirement, regardless of the method used. If we are fortunate, and I have the faith in our technology that we will be, the cost of removal will be between 5% and 15% of the original cost of the plant in today's dollars.

I hope that you will pardon me if I chuckle at the drama some of our associates feel compelled to introduce into this problem. It has been my experience that conventional plants and other utility installations are retired and removed from service when they have outlived their usefulness, but now I am told that nuclear power plants are "decommissioned". Now, don't get me wrong; it is not my intent to down play the importance of the safety considerations, the magnitude of the costs involved, or the time and effort expended when removing a nuclear reactor from service. The technology is complex, and the funds involved are of a magnitude unequaled in our history. However, the basic problem remains the same. Some installations are expected to have a value which exceeds the cost of removal when they are retired. This estimated salvage value is deducted from the original cost of the plant to determine the depreciation to be collected from the ratepayers. If the cost of removal exceeds the salvage value, then this negative salvage is added to the original cost to determine the depreciable investment. I will not be rebellious, however, and for the sake of good communication I will concede that we "decommission" nuclear power plants at the end of their useful life.

When any regulator is asked questions as to his attitude on decommissioning, I believe his initial response would be that he has two primary concerns: safety and cost. Public safety is of course the most important factor to consider in decommissioning a nuclear plant. As you are probably aware, the Nuclear Regulatory Commission has sponsored several studies to develop background information to support the preparation of standards covering decommissioning. Battelle Pacific Northwest Laboratory has prepared reports concerning technology, safety and costs of decommissioning a nuclear fuel reprocessing plant and a pressurized water reactor power station. Since there are presently four PWR generating units under construction in Texas, I am naturally most concerned with their decommissioning. To the best of our abilities, the Engineering staff at the Texas Public Utility Commission will continue to monitor the current situation and state of the art which will determine the best procedures for decommissioning a nuclear reactor. The Nuclear Regulatory Commission has done much good work in this area, but they have also made mistakes. They need our input, and we cannot be responsible to our profession and to the public interest unless we evaluate alternatives and provide informed input. The NRC is certainly the leader and the focal point for developing standards. But if they are left to do it on their own, much could be left out, and there is an excellent chance that costly mistakes will be made. I would simply urge that all of us continue to keep nuclear reactor decommissioning high on our list of priorities with regard to the development of standards and technology.

Because of the absolute need to decommission a nuclear reactor, and because of the huge sums of money involved which must be expended over a relatively short period during dismantlement, the public, or at least some of those who purport to represent the public, have become concerned as to whether or not the utility will be able to afford the costs of removal. On the surface, this makes sense. If the utility could not decommission a coal plant, it would be an eye sore, but there would be little concern for safety. But a nuclear power plant is a different matter all together. Large volumes of lethal radioactive materials inhabit the vacant nuclear power plant. Because of fear of radiation, the public demands that the utility have the capability to safely remove and dispose of these materials. Due to the purported uncertainty of the public in the utility's ability to afford decommissioning, it has been strongly suggested the conventional method of collecting removal costs through depreciation expense be abandoned in favor of a fund set up specifically to collect this money. The money could not be used for any other purpose, thus guaranteeing, funds will be available for decommissioning when the plant is removed from service. This, of course, is a serious departure from the normal and accepted methods of collecting funds for plant retirement costs. While such a proposal has certain cosmetic and political appeal, the ultimate costs to the ratepayer under this method should be estimated and weighed against those benefits.

While I believe I have retained an adequate level of objectivity with regard to the cost study contained herein, I must convey up front this personal consideration: If the utility cannot affort to decommission a power plant, there will be far greater concerns for the utility ratepayer! To suggest a fund is necessary implies that utilities in the future will be insolvent or will be unable to raise funds for any purpose. If this were the case, I seriously doubt the utility would even be able to provide electricity. This, my friends, would be a crisis. It becomes rather inconsequential under those circumstances whether or not there is money to pay for decommissioning costs. It is therefore my personal opinion that there is no need to treat nuclear decommissioning costs differently than retirement costs on any other project. Let's assume for the moment, however, that either I am wrong in my opinion or that those who have the power to make decisions differ with my opinion.

When I was asked to speak on this particular subject, I asked myself this question: all other things aside, will the creation of a fund save or cost the ratepayer money? I decided to compare the revenue requirements under the accepted negative net salvage accumulation treatment (method 1) versus the establishment of an external fund to accumulate the negative salvage requirement (method 2). I elected to use fund interest rates of 8%, 10%, and 12%.

The following premises and assumptions were made:

1. Discount rate for present worth calculations: 10%.

2. Embedded cost of capital: 10%.

3. Capital structure: Debt 50%
   Equity 35%
   Preferred 15%

4. Decommissioning costs: 10% of original cost.

5. Plant Life: 30 years.

6. Income Tax Rate: 46%.

Both methods were studied under the present income tax treatment and a more favorable tax treatment under consideration by Congress. Under the current tax treatment, a credit is established at decommissioning under both methods in exactly the same amount and, thus, has no impact on the study results. Under the most favorable income tax treatment, however, tax credits are accounted for on a current basis so no final credit at decommissioning is available.

Property taxes, insurance and revenue related taxes were not included in this study since these items are either immaterial or based upon a percentage of total investment or revenue and have no impact on the study results.

In a hypothetical case, an initial per unit investment of $100,000 is placed in service at the beginning of year one and retired at the end of year thirty. The investment is depreciated on a straight line basis for book and an accelerated basis for tax. Investment tax credit is claimed in year one and amortized on a straight line basis over the life of the investment. Capital costs and federal income taxes are calculated on an annual basis. Without any salvage considerations, this model is the "base case". The revenue requirements from the base case are added to the revenue requirements associated with decommissioning when an external fund is provided to calculate the total revenue requirements.

A second case is developed with a negative net salvage rate of ten percent. This model presumes current reinvestment in other utility plant of the decommissioning annuity. As a result of the current reinvestment of the decommissioning annuity, the effective investment in the nuclear facility is reduced and, in turn, the capital and income tax costs are reduced. Under present income tax provisions, the decommissioning annuity is not currently expensed for tax purposes.

A third and final case, similar to the second, presumes a more favorable tax treatment which permits current expensing of the decommissioning annuity for tax purposes. A summary of the annual, total and total present value of the revenue requirements for these cases are presented in Table I.

Tables II and III are descriptive of the revenue requirements associated with an external fund with an eight percent interest rate for both present and most favorable income tax treatments. Table IV provides a complete summary of the total and total present value of revenue requirements under each method for all three assumed fund interest rates.

Based on the study results it appears the interest rate to be earned by the external fund must be at least 2% greater than the composite cost of capital for the utility before the creation of an external fund can be economically justifiable. However, this close proximity of interest rates and utility cost of capital will exist only briefly during unusual times when money market certificates of deposit experience sudden and extraordinarily high increases in their interest rates. Last March, in fact, new money market CD's were bearing interest in the range of 15 to 16%. However, recent issues of top quality utiilty bonds are also being sold at near 15%, and interest rates on new CD's this month have fallen to about 12%. State regulatory bodies are now authorizing returns on utility common equity of approximately 15%. We must also remember investment in a utility involves risk; money collected for the fund will be invested in CD's or other no- or low-risk securities.

I could engage in a lengthy discussion of where all this is taking us, but to get to the point, in my opinion, in the long run, fund interest rates will average at least 4% below the utilities' composite cost of capital. A conservative comparison can be made, utilizing the results of this study, by comparing the study made with the fund interest set at 8% and the utility composite cost of capital set at 10%. This comparison indicates a savings of .85% of the original cost of the plant if the traditional method of collecting funds for negative net salvage is used. Under the most favorable tax treatment, 3.1% of the original cost is saved. Based on this comparison, assuming a 2500 megawatt, two unit nuclear power plant is placed in service today at a cost of two billion dollars, the utility's ratepayers would have to pay at least an additional $17,000,000 in today's dollars over the life of the plant if an external fund is created.

Based on cost alone, the establishment of a fund is not justifiable. In the final analysis, however, it will be up to either the regulators, the state legislatures or the federal government to decide for the ratepayer whether or not the piece of mind of knowing that the decommissioning will be there is worth this extra cost. In my opinion, it is not.

NUCLEAR DECOMMISSIONING STUDY

REVENUE REQUIREMENT

Year	Case 1	Case 2	Case 3
0	17,977	18,594	18,310
1	17,149	17,716	17,400
2	16,343	16,861	16,515
3	15,560	16,028	15,655
4	14,800	15,219	14,820
5	14,063	14,432	14,011
6	13,349	13,668	13,226
7	12,657	12,927	12,467
8	11,988	12,208	11,733
9	11,343	11,513	11,023
10	10,720	10,840	10,339
11	10,120	10,191	9,681
12	9,542	9,564	9,047
13	8,988	8,960	8,438
14	8,456	8,378	7,855
15	7,948	7,820	7,296
16	7,462	7,285	6,763
17	6,999	6,772	6,255
18	6,559	6,282	5,772
19	6,141	5,815	5,314
20	5,747	5,371	4,881
21	5,375	4,950	4,474
22	5,027	4,551	4,091
23	4,701	4,176	3,734
24	4,397	3,823	3,402
25	4,117	3,493	3,095
26	3,837	3,163	2,788
27	3,557	2,833	2,481
28	3,276	2,503	2,174
29	2,996	2,173	1,866
Total	271,193	268,108	254,906
PV Total	117,489	119,480	115,527

Case 1: No salvage, base case
Case 2: 10% negative salvage - present tax treatment
Case 3: 10% negative salvage - most favorable tax treatment

Table I

NUCLEAR DECOMMISSIONING FUND

REVENUE REQUIREMENT UNDER

PRESENT TAX TREATMENT

End of Year	Annual Revenue Required	Interest Income @ 8%	Tax Expense @ 46%	Cumulative Fund Value
0	289.74			
1		23.18	143.94	168.98
2		36.70	150.16	345.26
3		50.80	156.65	529.15
4		65.51	163.42	720.99
5		80.86	170.48	921.11
6		96.87	177.84	1,129.88
7		113.57	185.52	1,347.67
8		139.99	193.54	1,574.87
9		149.17	201.90	1,811.89
10		168.13	210.62	2,059.14
11		187.91	219.72	2,317.07
12		208.55	229.21	2,586.15
13		230.07	239.11	2,866.85
14		252.53	249.44	3,159.67
15		275.95	260.22	3,465.15
16		300.39	271.46	3,783.82
17		325.89	283.19	4,116.26
18		352.48	295.42	4,463.06
19		380.22	308.19	4,824.85
20		409.17	321.50	5,202.26
21		439,36	335.39	5,595.97
22		470.86	349.88	6,006.70
23		503.72	364.99	6,435.17
24		537.99	380.76	6,882.14
25		573.75	397.21	7,348.43
26		611.05	414.37	7,834.86
27		649.97	432.27	8,342.31
28		690.56	450.94	8.871.67
29	289.74	732.91	470.42	9,423.91
30		777.09	490.74	10,000.00
Total	8,693.21	9,826.21	8,518.52	
PV Total	3,004.53			

Table II

NUCLEAR DECOMMISSIONING FUND

REVENUE REQUIREMENT UNDER

MOST FAVORABLE TAX TREATMENT

End of Year	Annual Revenue Required	Interest Income @ 8%	Tax Expense @ 46%	Cumulative Fund Value
0	161.98			
1		12.96	5.96	168.98
2		26.48	12.18	345.26
3		40.58	18.67	529.15
4		55.29	25.43	720.99
5		70.64	32.49	921.11
6		86.65	39.86	1,129.88
7		103.35	47.54	1,347.67
8		120.77	55.56	1,574.87
9		138.95	63.92	1,811.89
10		157.91	72.64	2,059.14
11		177.69	81.74	2,317.07
12		198.32	91.23	2,586.15
13		219.85	101.13	2,866.85
14		242.31	111.46	3,159.67
15		265.73	122.24	3,465.15
16		290.17	133.48	3,783.82
17		315.66	145.21	4,116.26
18		342.26	157.44	4,463.06
19		370.00	170.20	4,824.85
20		398.95	183.52	5,202.26
21		429.14	197.40	5,595.97
22		460.64	211.89	6,006.70
23		493.49	227.01	6,435.17
24		527.77	242.78	6,882.14
25		563.83	259.22	7,348.43
26		600.83	276.38	7,834.86
27		639.75	294.28	8,342.31
28		680.34	312.96	8,871.67
29	161.98	722.69	332.44	9,423.91
30		766.87	352.76	10,000.00
Total	4,859.43	9,519.57	4,379.00	
PV Total	1,679.68			

Table III

Table IV

NUCLEAR DECOMMISSIONING STUDY - TOTAL AND TOTAL PRESENT VALUE OF REVENUE REQUIREMENTS

	Method	Actual Plant	Actual Fund	Actual Total	PV Plant	PV Fund	PV Total
Fund Interest Rate-8%							
Present Tax	1	268,108	0	268,108	119,480	0	119,480
Treatment	2	271,193	8,693	279,886	117,489	3,005	120,494
Most Favorable	1	254,906	0	254,906	115,527	0	115,527
Tax Treatment	2	271,193	4,859	276,052	117,489	1,680	119,169
Fund Interest Rate-10%							
Present Tax	1	268,108	0	268,108	119,480	0	119,480
Treatment	2	271,193	7,095	278,288	117,489	2,452	119,941
Most Favorable	1	254,906	0	254,906	115,527	0	115,527
Tax Treatment	2	271,193	3,998	275,191	117,489	1,382	118,871
Fund Interest Rate-12%							
Present Tax	1	268,108	0	268,108	119,480	0	119,480
Treatment	2	271,193	5,763	276,956	117,489	1,992	119,481
Most Favorable	1	254,906	0	254,906	115,527	0	115,527
Tax Treatment	2	271,193	3,274	274,467	117,489	1,131	118,620

A MAJOR STRUCTURES DECOMMISSIONING PROGRAM

Cliff Swedenburg, P.E.
Chief Engineer
Minnesota Public Service Department

I'm delighted to be here and to have a part in this distinguished conference and to participate in a discussion of "State Commission Attitudes on Decommissioning." My remarks will be from the standpoint of the departmental staff which advocates positions or programs such as this before the Minnesota Public Service Commission. In Minnesota the department staff and the Commission are separate and have different roles. The department staff has an advocacy role and the Commission has a legislative and quasi-judicial function.

Since depreciation certification and negative net salvage are instrumental in calling attention to the need for a major structures decommissioning program, let me take a minute to discuss them as they pertain to the Minnesota program.

Minnesota Depreciation Certification Program

In accordance with a specific set of depreciation rules, each regulated utility in the state is required to conduct a depreciation study every five years and to submit to the Commission for certification its rates and methods. The purpose of the program is:

1. To provide the means for determining appropriateness of depreciation rates and methods.

2. To insure frequent reviews and periodic studies of life and salvage and to avoid under or over-accrual.

3. To fix the proper level of depreciation accruals so that present ratepayers, insofar as is humanly possible, pay only for the current costs of utility service.

4. To allow flexibility in utility proposed methods of life analysis, life estimation and salvage estimation with the straight-line method of determining the depreciation accrual required unless an exemption is granted.

5. To fix depreciation rates and methods in a procedure separate from a hearing on a general change in rates.

Major Structures

In reviewing depreciation studies in Minnesota, the staff has found the accounts fall generally into two categories and consequently find the following definitions useful:

Major Structures Account - An account containing certain classes of property such as buildings, telephone COE, or electric or gas production plants. A general characteristic of these classes of property is that they are made up of a relatively small number of structures, each consisting of property of various types and ages, so associated in their use that the entire structure is finally retired at one time. For such classes of plant, while some units are retired during the structure's life span, the final retirement of the structure <u>suddenly</u> terminates the life of all the groups of units then incorporated in the unit.

<u>Group Property Account</u> - An account consisting of large numbers of similar units, the life of any one of which is not, in general, dependent upon the life of any of the other units. For such classes of plant, the retirement of a group of units occurs <u>gradually</u> until the last unit is retired. The retirements and additions to the account occur more or less continually and systematically.

In general, the staff has felt the proper method of life estimation for major structures to be the forecast or life span method. Also most major utilities choose to use the Remaining Life method of determining depreciation accruals for major structures accounts.

<u>Negative Salvage</u>

Salvage (Estimated Net Salvage which means scrap value minus the cost of removal) has traditionally been a part of the depreciation accrual formula. If, for example, upon retirement it was estimated that for every $100 of capital you could realize a $10 net of scrap sales over cost of removal you would then write off $90 over the life of the plant. This is referred to as a 10% positive net salvage. By the same token, if it was estimated that removal costs would exceed scrap sales by $10 for each $100 invested you would be entitled to write off $110 over the life of the plant. This is referred to as a negative net salvage.

<u>The Problem</u>

Negative salvage and major structures in themselves are <u>not</u> a problem.

Group accounts, such as gas mains and services, have been observed to have much larger negative salvage percentages than most major structures. Retirements usually occur monthly on a fairly systematic basis so that the decommissioning problem has been diffused into a "pay as you go" type of exercise. Some major structures such as buildings or telephone COE actually have resale value or positive net salvage. Most hydro facilities in Minnesota are small (megawattage wise) and do not indicate large removal expenses.

Realizing that a characteristic of a major structure is that upon final retirement the whole structure goes down and that the decommissioning is site oriented, it is understandable that everything went along in a rather calm manner until large major structures became subject to millions of dollars of removal expense compounded by inflation of labor rates, environmental restrictions and the lack of a scrap market for the larger components. The large major structures involved are nuclear generating plants, large coal generating plants, off-shore gas wells and potentially all large generating plants.

The problem in the conventional straight line depreciation approach occurs when you have a major structure with an estimate net salvage that is a significant percentage of gross plant and is also negative.

Staff Regulatory Philosophy

Going back to both the Remaining Life and the Average Service Life accrual formula we see estimated net salvage is included. The intent of having salvage as an ingredient in the accrual formula is to allocate the net cost of an asset to annual accounting periods, making due allowance for the net salvage, positive or negative that will occur when the asset is retired. This concept carries with it the notion that ownership of property entails the responsibility for its ultimate abandonment or removal. Hence, if the current users of the property benefit from its use, they should pay their pro-rata share of the costs associated with the removal of the property.

Most commissions, however, exhibit nervousness when asked to order the present ratepayers to pay their share of a rather large expense, which may or may not occur, the exact magnitude of which is not known, at an estimated time in the distant future.

The staff philosophy is simply that those who obtain the service should pay all costs connected with obtaining service which includes future decommissioning expense.

A Proposed Program

In general staff will propose a "Major Structures Decommissioning Certification Program" (MSDCP) which will be an offshoot or satellite of the present Depreciation Certification Program. It might work as follows:

1. During the review of a depreciation study, the major structures with a significant decommissioning cost will be identified and put under the MSDCP. The salvage used in the depreciation study will then be set to zero, the depreciation study would then focus only on capital recovery for that structure.

2. If the utility was not using (by plant site) the Forecast or Life Span method of life estimation and the Remaining Life method of determining depreciation accruals, they would be ordered to do so (all of the utilities with this problem now do or are in the process of doing so).

3. With the same RL from the depreciation study the decommissioning program could operate as follows:

   a) Initially and every five years an engineering study would estimate the site decommissioning costs in today's dollars.

   b) Every year the decommissioning estimates would be updated to account for inflation.

   c) The annual expense calculated for these future costs might be invested in an interest bearing fund that the utility could not touch or in some sort of internal fund.

The interest income of an external fund could help to increase the fund balance and reduce future expense.

The value of the MSDCP is that it separates the problem of depreciation (capital recovery) from that of liability for future site restoration or major structures decommissioning liability. In 3c above, the concept of an interest bearing fund that the utility could not touch is an interesting notion. Actual experience or further study may suggest some other type of financial scheme. The financial scheme to be favored has not yet been decided upon.

Joint MN/PSD - NSP Pilot Project

Northern States Power Company (NSP) has two nuclear plants in Minnesota that have been selected as a pilot project to test the concept of the MSDCP. Department staff and a team from NSP headed by Roy Berglund are engaged in arriving at a plan that will specifically pertain to the two NSP nuclear plants but be generic in nature so that it may be used by all utilities in Minnesota for all major structures identified in the MSDCP. The alternative financial methods under serious consideration include:

1. Straight line methods

    a) Status-quo. Depreciation accrual rate for each plant based on individual remaining lives with net salvage.

    b) Price level adjusted net salvage method.

2. Funded reserve for net salvage.

3. Sinking fund accrual for net salvage.

Another alternative, that of recovering removal costs only after they have been incurred, was not seriously considered because it did not coincide with staff regulatory philosophy. A brief description of the alternate means of providing for decommissioning costs follows.

Alternative 1a. Depreciation accrual rate for each plant based on individual remaining lives and net salvage. By this method, the depreciation accrual rate is determined by dividing the net plant less the net salvage by the estimated remaining life of the plant. The net plant consists of the original plant cost less the depreciation reserve accrued to date and to be correct the net salvage value should be the estimated future cost. This method is presently used by NSP to recover the costs of utility property. In equation form the depreciation accrual can be expressed as:

$$\text{Depreciation} = \frac{\text{Net plant-net salvage}}{\text{Remaining life}} \quad \text{(dollar form)}$$

A variation of this approach would be to separate the plant depreciation accrued from the estimated net salvage. In effect, the net salvage accrual would be considered an expense separate from plant depreciation and the plant cost recovered as depreciation on a remaining life basis.

The "negative salvage" straight line depreciation method is presently used by most utilities. As can be seen by the equation, a large negative net salvage increases the accrual rate so that more than the original cost is recovered over the service life. Hence, since the reserve is larger than the plant, in the latter years this method results in a negative contribution to the rate base. This is acceptable from an accounting viewpoint provided the difference between actual and estimated decommissioning costs are equated following the decommissioning.

A possible method to provide visibility to the need to correct the rate base is to establish separate accounts for the accruals, one for recovery of the plant and the other for the expenses associated with the expected net salvage cost.

This method results in large level dollar accruals for net salvage expense based on an estimate of future costs. If the total cost to the customer is considered, that is net salvage expense plus return, plus income tax effects, the customers in the later years contribute less (actually receive a credit) than those in the early years. The effect of inflation on purchasing power is to aggravate this trend. While a generating plant is expected to show a slight decline in usage with age a decreasing cost for its services might seem logical. However, the decreased cost to the customers by this method will be greater than the expected decline in usage.

Alternative 1b, Price level adjusted net salvage. This method is basically a modification to a part of Alternative 1a. It has been proposed for ease of calculations that net salvage be accounted for separately from depreciation of the plant and expensed on a remaining life basis. This is necessary since the estimated net salvage is recalculated each year to account for the effect of inflation on costs. As conceived, the plant would be depreciated to zero salvage by a remaining life technique. The negative net salvage would be recovered by a remaining life technique also; however, the net salvage would be increased each year to estimated current costs. This could be accomplished either by re-estimating the costs or using price indices. The equation form for the net salvage expense would be:

$$\text{Net salvage expense} = \frac{\text{Price level adjusted net salvage less accrued provision for salvage}}{\text{Remaining life}} \quad \text{(dollar form)}$$

This method requires the net salvage accrual to be separated from the plant depreciation accrual and also requires that the prior accrued provisions for net salvage be subtracted from the annually revised estimate of net salvage to obtain the remaining net salvage expense.

This method represents a formalization of the accruals that would be expected if the present straight line approaches based on current removal costs were continually (yearly) updated to account for changes in estimated removal costs. At present, most depreciation studies are usually performed on a five year basis or when significant changes are indicated. The price level adjusted approach improves this response time. Also it should be noted that while the pure straight line approach overcharges customers during the early years of the plant life (based on revenue requirements) to the benefit of customers in later years, this criticism does not apply to the price level adjusted approach to the extent of the straight line approach. Also, this approach has the benefit of not requiring forecasts of future inflation in making calculations.

Alternative 2: Funded reserve for net salvage. This approach establishes a separately funded reserve for accumulation of expected net salvage costs. The depreciation accruals for the net salvage cost would be calculated in the manner of Alternative 1b, that is a price level adjusted net salvage cost expensed on a remaining life technique. However, these accruals would be deposited in a separate fund that could not be used by the utility and which would draw interest. The accruals would be reported as an expense by the utility. The interest income of the fund would help to increase the fund balance and hence reduce the future expense.

The interest income would be considered taxable income, although the possibility exists that special future legislation could make this fund a tax free fund. Another option of the fund would be to invest in tax free securities.

Advantages of this method include: the availability of the fund to finance the decommissioning independent of the future viability of the utility; complete separation of plant depreciation from decommissioning costs; and elimination of the accrual as a reduction from rate base. However, this method eliminates the expense accrual as a source of funds to the utility. Hence, additional utility financing will be required with the resulting additional costs for return on this new capital. Also, this method is opposite to the straight line approach in that the future customers will pay more for the decommissioning compared to the current customers. This may be desirable if the effect of inflation on purchasing power is considered.

Alternative 3: Sinking fund accrual for net salvage. In order to apply this method, the accrual for net salvage has to be separated from the depreciation accrual for the plant. The net salvage cost is then estimated as the net cost at date of decommissioning. A sinking fund accrual is then utilized to recover the estimated future cost. The sinking fund accrual consists of an annuity, the future value of which is sufficient to decommission the plant at date of decommissioning. It is suggested that the discount rate for the annuity be the allowed rate of return for rate purposes. Another alternative, which results in the revenue requirements being level, is to use a discount rate equal to the tax-adjusted cost of capital.

In this method the accrual and associated interest is recorded as an expense, and deducted from the rate base. This method charges the customers an increasing yearly expense (accrual plus interest) with the possibility of future adjustments for changes in allowed rate of return or final decommissioning costs. Theoretically, if the discount rate is chosen to be equal to the tax-adjusted cost of capital, the interest portion of the expense will be exactly offset by return on rate base resulting in a level revenue requirement. Also, future costs have to be estimated.

Prognosis

The utility has recategorized the decommissioning alternatives initially considered for evaluation. These can be divided into three broad categories of external fund, internal fund, and "other."

EXTERNAL FUND

1. Precommissioning Fund
2. Price Level Adjusted
3. Sinking Fund

INTERNAL FUND

4. Straight Line
5. Price Level Adjusted
6. Sinking Fund

OTHER

7. Payment at Decommissioning
8. Surety Bond
9. Insurance
10. General Tax Revenues

Whatever alternative the staff and NSP decide is best will have to face the test of public and Commission scrutiny in the hearing process. Staff and NSP are attempting to keep their relationship non-adversary. It is hoped that a generic financial plan will emerge that may be used for all major structures to be included in the MSDCP. Of course, any plan chosen will have to be reviewed peridocally to reassess the estimates and assumptions utilized in developing the accrual rates. Although the immediate hearings concern two nuclear plants, we feel an overlooked and potentially serious problem exists in decommissioning large coal-fired plants.

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NINETEENTH SESSION, Thursday, May 22 - 3:00 p.m.

Concurrent Session H-1

ACCOUNTING FOR PROJECT AND SPECIAL FINANCINGS

CHAIRMAN: Richard Walker, Senior Partner
Arthur Andersen & Company
Board of Directors, Iowa State Regulatory Conference

SPEAKER: Richard Dieter, Partner
Arthur Andersen & Company

ACCOUNTING FOR PROJECT AND SPECIAL FINANCINGS

Richard Dieter
Partner
Arthur Anderson & Co.

The public utility industry and other capital intensive industries face tremendous problems today in raising funds for maintaining present capacity and for expansion. In addition, the sophisticated nature of today's financings--the financial techniques used--have strained the traditional accounting model for reporting assets and liabilities. Given these factors and the desire by many to keep debt off the balance sheet for a variety of reasons, the subject of accounting for project and special financings is both timely and instructive, even though such accounting is in a rather confused state of affairs.

The reasons for corporations, including public utilities, desiring to keep debt off the balance sheet, vary. They range from improving return on stockholders' investment, particularly when the assets are not in a revenue producing staff, to lowering the debt to equity ratios in the belief that this may influence its credit rating and potentially reduce interest costs. In some cases the use of off balance sheet financing eleminates the need for regulatory approval for the outside financing. One interesting facet with this line of thinking is that, in some situations, to the extent the assets are not reflected on the balance sheet, the utility is often not permitted to earn a return on the underlying assets. As a result, the risk to the equity holder may be unduly increased--no yield to him from asset utilization--only a pass through of the financing cost. However, let us focus on the accounting issues, not the motivations involved.

First let us consider the existing accounting model for financings and describe certain of the new techniques being used and how and why today's accounting model fails to capture their economic substance. Then analyze the recent pronouncements by the accounting rule making bodies in this area and finally consider the purpose of financial statements and their potential impact upon future financings for the public utility industry.

PRESENT ACCOUNTING MODEL

In evaluating the appropriate method of accounting for project and special financings, two key areas must be examined. First, what constitutes the difference between a liability that should be recognized in an entity's balance sheet and a contingent liability that may be disclosed in the footnotes to the financial statements, and secondly, what is the appropriate method of accounting for assets and their related utilization and liabilities when they are shared or divided among several entities. By understanding what the traditional accounting model yields for guidance in these areas, one is able to form initial judgments as to the existing accounting followed for such financing techniques as purchased power and take or pay contracts, throughout arrangements, assets and liabilities during construction, and joint ownership situations. It also demonstrates that the existing accounting model, as developed many years ago, is unable to cope with the legal and economic complexities present in many of these newer financing techniques.

WHAT IS A LIABILITY?

The authoratative literature defines liabilities in terms of economic obligations. It concludes that "The economic obligations of an enterprise at any time are its present responsibilities to transfer economic resources or provide services to other entities in the future". An expansion of the definition given is that economic obligations include both obligations to pay money or to provide goods or services. The focus of the literature is that liabilities are the <u>present</u> responsibilities of the entity and that they are the result of prior events and transactions and not of future transactions. The literature also emphasizes measurement; that is, the amount of economic obligations must be known or subject to reasonable estimation before it is reflected in an entity's balance sheet.

Guarantees of indebtedness and rights to receive future goods and services on the other hand are usually viewed in the accounting literature as executory contracts and accordingly are not given current recognition as assets and liabilities. A noteable exception is the accounting treatment afforded certain leases prescribed by FASB Standard No. 13. Nevertheless, in most situations, the literature concludes that when the guarantor is only contingently or secondarily liable for the indebtedness or when the obligation is for future goods and services, disclosure of the contingencies and future commitments is appropriate.

The term "guarantee" according to Webster's dictionary represents "an assurance for the fulfillment of a condition as an agreement by which one person undertakes to secure another in the possession or enjoyment of something or to undertake to answer for the debt, default or miscarriage of, or to give security to". Fortunately or unfortunatel depending on one's perception, the underlying nature of the other person or entity is not distinguished in the accounting literature. For exampl in the public utility arena, unconditional take or pay and throughput contracts assigned directly to financing institutions secure the project's financing but are classifed as executory contracts. Often, under the take or pay and throughput agreements, the full credit of the utility is also given. In many instances, without the existence of these guaranteed payment type contracts, the collateral of the project would not be sufficient to support the high level of indebtedness of the project at the rate of interest that was negotiated.

Nevertheless, since the "obligation" is viewed as contingent (i.e., based upon a future event) the contract is not accounted for as an asset and liability and is dealt with via the disclosure approach.

PARTIAL OWNERSHIP ACCOUNTING

Complicating the notion of executory contracts in project financings, many projects, formed as separate entities, are jointly owned creating the potential for presenting the equity interest as a one line item on the balance sheet. The authoratative literature in accounting for joint ventures (APB Opinion No. 18) focuses on the percentage ownership of an investee as the principal determinent for the method of accounting to be followed for a particular investment. Ownership interests in excess of fifty percent are assumed to be controlling and therefore subject to consolidation in most situations. In evaluating how traditional accounting pronouncements deal with joint ownership situations of less than fifty percent, it is important to note that APB Opinion No. 18 was written and issued to solve a perceived problem of income recognition; its effects on the balance sheet were a secondary and relatively insignificant factor in the Accounting Principles Board's consideration. In addition, at the time of issuance, most joint ownership situations involved ownership of common stock in operating companies that dealt with (i.e. customers and vendors) third parties. Joint ventures for projects whose sole purpose was to supply products or service to the participants were relatively uncommon at that time and accordingly, little attention was given to the balance sheet issues that have arisen today. This has become particularly acute since many joint ventures formed today are thinly capitalized and highly leveraged and are often structured to show breakeven results of operations.

Briefly, present accounting supports the following balance sheet treatment for joint ownership situations:

CORPORATE JOINT VENTURES

Defined as "a corporation owned and operated by a small group or business (the joint venturer) as a separate and sepcific business or project for the mutual benefit of the members of the group...a corporate joint venture usually provides an arrangement under which each joint venturer may participate directly or indirectly in the overall management of the joint venture. Joint ventures thus have an interest or relationship other than as passive investors". Joint ventures may also exist in the partnership form (i.e. unincorporated) and joint ventures may include partnerships and individuals as well as corporations. In situations where an investor has a 50% or less interest in a corporate joint venture, (almost all project financings structures in joint venture form have this ownership split), the accounting literature prescribes the use of the one line equity method for ownership interests of twenty percent or more. Under this method the investors share of revenues and expenses of an investee (the joint venture) are presented as one net amount in the investors income statement. The balance sheet of the investor reflects its investment at cost, adjusted for its share of the joint venture's net income and dividends of the venture after acquisition. The income and stockholders' equity reported by the investor are the same as if the accounts of the investee (the joint venture) were consolidated. However, the details reported in the financial statements, particularly the consolidated balance sheet, are usually significantly different.

UNDIVIDED INTERESTS

In certain situations, the accounting literature permits a method of accounting known as proportionate consolidation. In these situations, the liabilities associated with the assets owned through undivided interests are several in nature (e.g. each investor is liable for his portion of the liability and creditors have no claim or lien on the assets in excess of the debtor's interest therein). Under this method, the investor records its proportionate interest in the joint ventures' assets, liabilities, revenues and expenses on a line by line basis and combines these amounts directly with its own assets and liabilities without distinguishing between the amounts related to the joint venture and those held directly by the investor. However, the practice, an entity that wishes to avoid putting its share of the assets and liabilities of the venture on its balance sheet will opt for the traditional one line equity method. The use of the one line equity method is considered appropriate under APB Opinion No. 18 when the investor has the ability to exercise significant influence. Generally, an ownership percentage of 20-50% gives rise to the presumption that the investor is able to exercise significant influence. Investments of less than 20% are presented on the cost basis with income recognition limited to dividends received. Recently, however, situations have arisen when an ownership percentage of significantly less than 20% exists, yet the one line equity method has been used. However, it appears that the motivation in these cases relates to the income statement effect--namely, that the investor sought to record a proportionate share of the investees' income rather than to recognize income as dividends are received.

The result of the traditional accounting model in accounting for joint ownership through a separate entity is that an ownership interest of less than fifty but not less than twenty percent is presented on the balance sheet as a one line item, in effect, a netting of the proportion of the assets and liabilities of the joint venture owned by the investor, or as a one line item using the cost method. Both methods do not recognize separately the assets and liabilities of the joint venture on the balance sheet.

By combining the traditional accounting model's definitions of a liability and guarantees with the accounting treatment afforded joint ventures, one can quickly understand why the use of separate financing vehicles for large capital projects has risen dramatically in recent years. Agreements and debt guarantees can be structured whereby a thinly capitalized and highly leveraged entity exists, owned individually or jointly by several utilities, to supply power and generating facilities, without any reflection of the underlying assets and liabilities reflected on the balance sheet of the utility.

IMPACT OF THE SECURITIES AND EXCHANGE COMMISSION

Given the increasing use of joint ventures and other financing techniques that result in significant amounts of debt not appearing on the balance and some circumstances not disclosed, the Securities and Exchange Commission acted in December 1978 with the issuance of Staff Accounting Bulletin (SAB) No. 28 dealing with the accounting and disclosures by electric utility companies with respect to the use of financing through construction intermediaries, interest in jointly owned plants and long-term contracts for purchased power. While SAB's are not rules or interpretations of the Commission and do not bear the Commission's official approval, they do represent interpretations and practices followed by the Division of Corporate Finance and the office of the chief accountant in administering the disclosure requirements of the Federal Securities laws. To be sure, a registrant not following the guidance in an SAB will almost certainly be subject to further questioning on the issue.

The SAB indicated that an electric utility company financing the construction of a generating plant or its share of jointly owned plant through the use of a "construction intermediary" (such as a trust) should include the intermediary's work in progress in its balance sheet in the appropriate caption under utility plant. The related debt should be included in long-term liabilities and disclosed in a footnote to the financial statements. The SAB also indicated that the organization and purpose of the intermediary and the nature of its authorization to incur debt to finance construction on behalf of the electric utility should be disclosed in the notes to the financial statements.

With respect to an electric utility participating in an undivided interest in a jointly owned plant, the SAB suggests inclusion of a table in a footnote to the financial statements of the utility showing the amount of each jointly owned plant in service, the related accumulated depreciation, the amount of plant under construction and its proportionate share. The bulletin further states that the notes to the financial statements should reflect that the dollar amounts represent the participating utility's share in each joint plant and that each participant should provide its own financing. Note that the bulletin deals with an undivided interest in assets, not in a separate entity. Many question the need for these types of disclosures when the assets and liabilities are appropriately reflected on the balance sheet.

Finally, the SAB provides guidance on long-term contracts for the purchase of electric power. While apparently the Commission and its accounting staff considered the possibility of capitalization of purchased power contracts, the SAB concluded that only the terms and significance of the purchase contracts to the utility, including the date of contract expiration, utility share of the plant output being purchased, the estimated annual cost, annual minimum debt service payments required and the amount of long-term debt or lease obligations outstanding should be disclosed in the notes of the financial statements. Here again, the solution was one of disclosure, with no capitalization of the underlying asset or liability to be reflected on the balance sheet.

We have seen over the past few years different accounting treatment by public utilities with respect to purchased power contracts. For example, at least two utilities have adopted the practice of capitalizing the assets and the related obligation under a purchased power contract whereas others have followed the additional disclosure route.

FINANCIAL ACCOUNTING STANDARDS BOARD PROPOSED SOLUTION

Very recently, the Financial Accounting Standards Board released a proposed statement of Financial Accounting Standards, entitled "Disclosure of Guarantees, Project Financing Arrangements and Other Similar Obligations", an amendment of FASB Statement #5 "Accounting for Contingencies". The exposure draft concludes that disclosure of commitments involving potential loss contingencies is required even though the possibility of loss may be remote. The document includes examples of unconditional obligations such as take or pay contracts, throughput agreements, and vessel charters that require payment regardless of the circumstances. The board has concluded that the commitments under these types of arrangements and others that in substance have the same characteristics shall be disclosed. The disclosure should include a brief description of the nature of the obligation, if estimable, the value of any recoveries that could be expected to result, such as from the guarantor's right to proceed against an outside party, and for those commitments that require a lump sum payment upon the occurrence of some event, and the amount and duration of the commitment as of the latest balance sheet date. And finally, for those types of commitments that are often found in the financings of public utilities, whereby the utility is required to pay certain amounts periodically during the term of an agreement (such as a take-or-pay contract of throughput agreement) the commitment as of the latest balance sheet date and the amount of payments required in each of the next succeeding five years.

Interestingly, the Board notes in the exposure draft that certain guarantees and contracts discussed in the statement are already recorded as liabilities and assets on the guarantor's balance sheet and that the proposed accounting treatment in this statement or the treatment of future guarantees and contracts that are substantially the same as those guarantees and contracts already recorded should not be altered.

Thus, with the exception of the trust financing vehicle that has been acted upon by the SEC, the accounting profession has, as an interim measure, concluded that other types of financing techniques should continue to be accounted for under the old model but that expanded disclosure should be given to the reader and user of the financial statements.

WHAT ABOUT THE FUTURE

In the background material given in the exposure draft just discussed, the FASB has basically concluded that because of other topics on its technical agenda, primarily the conceptual framework project, no major changes in practice should occur at the present time. The Board notes that the ultimate solution to accounting for such matters as project financing agreements, take-or-pay contracts, throughput contracts, working capital maintenance agreements and other similar contracts, should await further progress on the conceptual framework project.

The Board believes that the subjects that are part of the conceptual framework which could impact the ultimate accounting for project financing agreements include:

1. What are the elements of the financial statements? (i.e., What are the specific definitions that can be used to set future accounting principles for such terms as assets and liabilities).

2. What are the criteria for determining when and whether particular assets, liabilities and other elements should be recognized in the financial statements?

3. How should assets and liabilities and other elements of financial statements be measured?

4. What types of information should be provided about an entity's funds and liquidity position?

It appears that the rationale of the FASB hinges upon the presumption that it might reach a different conclusion with respect to accounting for the various off balance sheet financing techniques employed today upon completion of its conceptual framework project and that it clearly wishes to avoid abrupt changes in financial reporting at this time. Given the magnitude of potential changes in financial reporting the Board is already working on (i.e., changing prices, pensions, regulated industries, and foreign currency), their position in this area is somewhat understandable.

Nevertheless, the disclosure vehicle being adopted for the present does not significantly aid users of financial statements to understand the economic effects of the transactions of the enterprise. Many believe the FASB already has the conceptual basis for a more appropriate method of accounting for these types of financing vehicles and joint ownership situations. The key lies in basing the accounting treatment on economic rather than legal notions. For example, using the FASB's proposed definition of liabilities (i.e., "probable future sacrifices of economic benefits stemming from present legal, equitable of constructive obligations to transfer assets or provide services to other entities in the future...") contained in one of the conceptual framework documents, the economic notion of a liability is given recognition. Carrying this definition to many of the off-balance sheet techniques used today, one is quickly able to reach the conclusion that they do represent "equitable and constructive obligations to pay future economic resources" and should be reflected on the balance sheet as liabilities.

Similarly, suggestions have been raised as how to better present joint ownership situations in the balance sheet of the investors. One proposal entitled the expanded equity method, would sanction a form of prorata consolidation for these ownership situations, whereby on the balance sheet of the investor its proportionate share of the assets and liabilities of the joint venture would be shown, separated from those assets and liabilities owned entirely by the entity.

Finally, let us recognize that any future accounting treatment of assets and liabilities should not be used to subvert or mask the real economic factors that utilities face in financing their huge capital projects. Rather, let the accounting treatment for assets and liabilities be neutral for all entities, so that users of financial statements such as credit grantors and rate regulators, are able to compare among entities and make the economic decisions required on the basis of economic facts and not alternative or deceptive accounting practices.

TWENTIETH SESSION, Thursday, May 22 - 3:00 p.m.

Concurrent Session H-2

CWIP-IN THE RATE BASE OR NOT?

CHAIRMAN: Fred C. Huebner, Administrator
Utility Accounts and Finance
Wisconsin Public Service Commission

SPEAKERS: Robert L. Hahne, Deputy National
Director-Regulated Business Practice
Deloitte Haskins & Sells

Robert G. Towers
Vice President
Hess & Lim, Inc.

WHY CWIP SHOULD BE IN RATE BASE

Robert L. Hahne
Partner
Deloitte Haskins & Sells

Although the financing cost of CWIP was treated in a variety of ways depending upon particular facts and circumstances, in the past, the majority of regulatory commissions capitalized these costs. They did this by (1) excluding CWIP from rate base and allowing capitalization, or (2) allowing CWIP in the rate base and concurrently crediting the related AFUDC to operating income as a reduction of revenue requirements. The widely quoted basis for deferring such costs was that property should be "used and useful" before it would be allowed in rate base with a current return. For many years, there was very little challenge to such capitalization procedures. However, conditions have changed dramatically in the past few years; such as the greatly increased costs of construction, the high costs of capital, and the extended construction periods. As a result of these changed conditions, the financing cost of construction has come under close scrutiny and has been the subject of much criticism. Because of this, there is a trend among regulatory bodies to allow CWIP in the rate base and not capitalize AFUDC. As the New York Public Service Commission stated in Opinion No. 75-1, Case 26552, Re Long Island Lighting Company, dated January 9, 1975:

> a. "Traditionally, rate base allowances for construction work in progress have been limited to an amount necessary to compensate the utility for projects whose small size or short duration made it administratively impracticable for interest to be capitalized - projects characterized as non-interest bearing construction. More recently, it has become apparent that other factors dictate larger rate base allowances for construction work in progress. In LILCO's last rate case, we took note of the claim that some investors and bond rating agencies view income which includes IDC in a less favorable light than income derived from the sales of utility services.
> 13 NY PSC 846, 850 (1973)..." (p. 3).
>
> b. ...There is little logic in setting rates which on their face appear just and reasonable, but which leave LILCO in a position where it is unable to finance even the most truncated construction program because the substantial impact which IDC has on the company's ability to sell securities is ignored." (p. 4)

In my opinion, this trend among regulators is most appropriate under present conditions and is the approach I intend to justify in this paper.

One of the positions taken against the inclusion of CWIP in rate base with a current return is that it violates the regulatory posture that property should be "used and useful" before it is included in rate base. In response to that, I would note that the "used and "useful concept was never closely followed in that inventories of fuel and materials and supplies, as well as plant held for future use, prepayments, and other working capital requirements were allowed in rate base.

This was done in recognition that these items are not currently "used and useful" but they provide assurance that the company would be able to continue to supply safe dependable service. The "used and "useful" argument was generally applied to the isolated issue of CWIP even though the investment in CWIP is made for the same purpose as the items just mentioned.

It might be beneficial to review the economic conditions which existed in the electric industry when the "used and useful" theory was used. During its development stage, the industry was building new plants and facilities to be able to provide the convenience of electricity to a larger proportion of our population. In its adolescent years, it continued to build additional capacity to provide energy for industrial development.

In the early 50's, the electric industry reached maturity in that basically the entire population of our country had the use of low cost electric energy. For the next 15-20 years, the industry continued to build to meet the increasing demands of each customer and the increasing size of our population.

Throughout this period of development, because of economics of scale, few environmental restrictions, and relatively low capital costs, the industry was able to construct new facilities which had a lower cost per KW than the facilities then in service. These conditions provided regulators with a basis for deferring the financing costs of new construction for ratemaking purposes. They recognized that the power generated and delivered through these new facilities would be cheaper than power generated by existing plants upon which current customer rates were based; therefore, to balance the interests of present customers with that of future customers, a case could be made for deferring the financing cost of new construction. Even though this was contrary to generally accepted accounting doctrine for industry in general, the accounting profession accepted this treatment for the utility industry as this was the basis for establishing rates and a matching of revenues and expenses could be achieved. The investment community accepted this basis because the industry was healthy in that more efficient plants were being built, construction periods were relatively short, and the industry had sufficient cash flow to meet the capital cost requirements until the plant went into service.

Over the past ten years, economic conditions in the industry have changed dramatically. The costs of new facilities are no longer less per KW than previous facilities for a number of reasons: (1) the benefits of economies of scale have slowed dramatically because, based on current technology, we are near the limit on the size of generating units, (2) inflation rates have greatly increased the cost of new construction, (3) the cost of money to finance construction is higher, and (4) a large portion of new construction is not for new capacity, rather it is for equipment to meet environment requirements or faster than normal replacement of plants using natural gas or oil.

As a result of these changed conditions, it should be obvious that today's customers are using the economic value of facilities that will cost a great deal more to replace per unit of capacity.

I believe that the trend by regulators to allow CWIP in rate base, in whole or in part, is based on a recognition of the different conditions that exist today than when the "used and useful" position was used by regulators to balance the interests of current and future customers.

These changing conditions are evident in the following statistics. In 1957, privately owned Class A and B utilities had an installed capacity of approximately 97.5 million KWs with an average cost of approximately $139/KW. Through 1967, the industry continued to beat lower levels of inflation rates so that by the end of 1967, there was approximately 203.8 million KWs of capacity with an average cost of approximately $128/KW. Even though capacity more than doubled, the cost per unit declined in excess of 8%, indicating that the cost of capacity installed in that decade averaged 15% less than that at year end 1957.

In contrast to that, by the end of the decade in 1977, capacity more than doubled again to approximately 433 million KWs with cost per KW increasing to over $172/KW. This indicates that the average cost of generating capacity added during that decade was more than $211/KW or 65% higher than the average at the end of 1967.

When even the $211/KW is compared to the cost of generating projects now under construction ($600-$1,200/KW) it is clearly evident that inflation in the cost of new construction has far surpassed any benefits in the economics of scale. I believe this information dramatically portrays the weakness of setting rates today based on the average unit cost of existing in-service plants. Such rates cannot support the new higher cost units now being placed in service.

The cost of money required to finance these new construction projects has also increased dramatically. Between 1967 and 1977, the embedded cost of long-term debt increased from approximately 3.86% to 6.88%. With the dramatically increased cost of debt experienced in the past few years, this trend is accelerating. Similar increases have been experienced in the cost of preferred and common equity.

As a result of these changed conditions, AFUDC, a non-cash item, nationally accounted for well over 25% of net income in 1977 compared to approximately 6% in 1967. Of course, the percentages are larger when compared to income available for common stock. In addition, when we remember these numbers are national averages, which include a large number of companies earning a current return on CWIP, it is not difficult to realize that in some companies AFUDC accounts for well in excess of 50% of income available for common. Recognizing that utility securities today are sold on a yield basis, it is imperative that dividends be maintained, resulting in payout ratios averaging well over 75% of income. Since non-cash income is in excess of the remaining 25%, it is quite obvious that at least a portion of current returns are being paid with new financings. Is it any wonder investors lack confidence in the industry and require higher returns for their investment.

These high percentages of AFUDC income also contribute to lower coverage ratios which, in turn, further jeopardizes the company's ability to raise the huge amounts of capital required to support the construction program of the industry.

If the CWIP units are included in the rate base, they will impact the rate base at the higher average unit cost and rates will be built at the level required to support the units when they go into service. The result is to help alleviate the attritional aspects that have been such a severe drain on the utility industry in the past few years.

In addition, the inclusion of CWIP in rate base has the effect of recovering, on a current basis, the costs associated therewith, rather than deferring such costs for future recovery. In my opinion, there are a number of benefits to such an approach, with no concurrent disadvantage to the consumer or to the company.

These benefits, in addition to the reduction in attrition, are:

1. Improved cash flow

2. Improved debt coverage

3. Reduced business risk.

Under AFUDC procedures, the costs associated with construction funds are credited to income and concurrently are added to the investment for future recovery through depreciation and return on the higher level of investment. Consequently, the book income is recognized during the construction period, but the <u>cash flow</u> through which the income is realized follows at a later date. With a change from the AFUDC credit to adequate rates on a current basis, the book credit will be transformed into cash income and a company's cash flow position will accordingly improve.

Most utility companies' bond indentures sharply limit the amount of "other income" allowable for coverage ratio purposes. If CWIP is not allowed in rate base, the large amount of AFUDC credits that will be generated will not be allowed in their entirety; whereas, if it is transformed into current rates and becomes an item of current revenues, it will be fully allowed for coverage purposes. Consequently, coverages will be improved by shifting from a book credit to a cash revenue credit.

With respect to business risk, when businesses get into financial difficulties, it is often due to lack of liquidity. The ability to operate on a day-to-day basis is affected more directly by the amount of cash on hand than by the reported earnings as reflected on financial statements. Consequently, as the cash position of a company improves, the risks that it faces in not being able to meet current commitments will be reduced. This is borne out very clearly by the experiences throughout the utility industry in the past few years, when cash position became very severe in many instances and many companies found themselves in critical operating positions. As the cash flow is increased, the risk attendant with maintaining the operation of the business is logically decreased. One of the highly significant features of this improved risk, which goes hand-in-hand with the cash flow benefits previously expressed, and which also affects the coverage of the company, is the fact that the financial soundness that flows from each of these points lowers the overall capital costs and facilitates the acquisition of capital. Furthermore, the cash flow feature reduces the capital needs that must be obtained from external sources. The sum total of these benefits is to improve the financial soundness of the company, lower its overall cost of capital and produce lower operating revenue requirements to be borne by the consumer. In this way, the CWIP changeover will produce very real benefits to the consumer.

I would acknowledge that the customer pays for the construction financing costs at an earlier date and, therefore, rates initially are higher to that extent. However, I have prepared an Exhibit to emphasize the point that absolute revenue requirements are lower over the life of property when CWIP financing costs are recovered currently. This Exhibit also shows that on a present value basis the costs to the customer are the same under either alternative.

Before reviewing the numbers on these schedules, I believe it is important to point out that I have not attempted to quantify the overall lower cost of capital which I believe results when CWIP is included in rate base. Also, I have not reflected the reduced revenue requirements resulting from lower taxable values of property when CWIP is included in rate base. This is not to suggest that I do not believe these additional benefits are produced. My point is that even without considering those benefits, the consumer is still better off.

I do not intend to spend a great deal of time reviewing the various schedules of this Exhibit. They are included as part of my printed material and you may review the assumptions used at your leisure. The two significant points are that the tax benefits of the interest payments during the construction year are deferred and claimed through depreciation over the property life. This is done to isolate the issue of tax normalization from the issue at hand.

The second significant point is the discount rate used to calculate present values of revenue requirements. I have used the 10% rate of return used in calculating the Company's cost of capital. In my opinion, this is an extremely conservative discount rate because I do not believe that the average residential customer can earn an after tax return equivalent to the utility's allowed return.

In using the utility's allowed return as the discount rate, the present values will always be the same. Of course, if a savings account interest rate is used, the present value of revenue requirements when CWIP is included in rate base will be substantially lower.

There are some individuals who in presenting comparisons of present value requirements of the CWIP alternatives represent that the discount rate should be the short-term credit rate (18%). Their basis for taking this position is that most residential customers are net debtors. While these customers may have loans outstanding, I question whether they are net debtors. Many people do have real estate loans outstanding or car loans outstanding, both of which are secured with related assets. However, I do not accept the premise that these customers borrow money on a monthly basis to pay their utility bills.

If that were true, it would seem logical to me that the utility's allowed return would have to be in excess of 18% to account for the utility's higher risk than the finance company's. The finance company can make a judgment whether to loan the customer money to pay for utility services received. The utility company, by its franchise, has to supply service until the customer does not pay for services received.

Therefore, logic tells me if the proponents of the position that short-term loan rates should be used as the discount rate, to be consistent, they would have to acknowledge the utility's rate of return should be increased at least to that level. That is necessary to account for comparable risk which they say has a cost rate of 18% as determined by the marketplace.

I believe I have addressed most all of the points normally raised by the proponents of continuing to capitalize AFUDC. However, my co-panelist on this program has, on occasion, stated that capitalizing financing cost of construction is required by generally accepted accounting principles. He refers to the "matching principle." Mr. Towers is entitled to his opinion, however, the Financial Accounting Standards Board has stated in Paragraph 49 of Statement 34:

> "Nevertheless, all Board members agreed that recognition of the cost of equity capital does not conform to the present accounting framework. In the present accounting framework, the cost of a resource is generally measured by the historical exchange price paid to acquire it. However, funds are an unusual kind of resource in that, although an enterprise obtains funds from various sources, only borrowed funds give rise to a cost that can be described as a historical exchange price".

I would add that I would accept the application of generally accepted accounting principles if applied to ratemaking. This would include comprehensive interperiod tax allocation, noncapitalization of a return on equity funds used for construction, etc.

In concluding my remarks, I believe it is also important for us as a nation to recognize some basic economic facts of life. I believe John O'Leary (former Deputy Secretary of Energy) summarized this very well when, in answer to a question regarding the consequences of our energy problems, he stated in recent testimony before the Utah Public Service Commission:

> "For the nation we are already beginning to experience some of the consequences. These are inflation at rates that simply have no modern precedent, the beginnings of recession, reductions in per capital income and reductions in productivity. The fact of the matter is that our society is absolutely dependent on the sustained availability of energy. Indeed, when we review the very long history of man's tenure on this planet, we find that throughout the world up until the last 200 years or so, per capita income was a remarkably even \$200 to \$250.00 (in today's dollars) in virtually all parts of the world. Today we find that in those parts of the world that for one reason or another have been unable to harness energy to accomplish a significant portion of their work, incomes remain at this subsistence level. This is true for the majority of the citizens of Asia, India and Africa and many in South America. In contrast, in those areas of the world where energy has been subjugated to man's use, we find an almost perfect correlation between per capita energy use on the one hand and per capita income on the other hand. Quite clearly we can, within limits reduce the amount of energy needed to

> sustain our way of life. When those limits are exceeded, and I think that there are incipient signs that they are now being exceeded, the standard of life suffers. This relationship is, it seems to me, the principal consideration that should be before the nation in making energy decisions."

With this background and the recognition of our nation's vulnerability by its dependence on foreign sources of energy, it is imperative that we maintain financially viable electric and gas utilities who will be able to generate the funds necessary to complete construction programs in a timely manner. I believe the inclusion in Rate Base of a significant portion of CWIP is one method of accomplishing this goal. In addition, it is my considered opinion that significant benefits accrue to the companies and their customers when this is done and that such benefits far outweigh any disadvantages.

Thank you.

COMPARISON OF THE COSTS OF $1,000,000 of CWIP
UNDER ALTERNATIVE RECOVERY PROCEDURES

ASSUMPTIONS

A. One unit of plant under construction for one full year, with costs of labor and materials of $1,000,000 outstanding for entire year.

B. ASSUME FINANCING OF THE CWIP AS FOLLOWS:

DEBT	$ 700,000	7.9%	$ 55,000
EQUITY	300.000	15.0%	45,000
	$1,000,000	10.0%	$100,000

C. Plant into service at the end of the year and a life of 20 years. Straight-line depreciation for both tax and book purposes, zero salvage and cost of removal.

D. A 10% rate of return during the life of the plant.

E. Use of beginning of year investment in the rate base.

F. The debt and equity capital is reduced annually as the plant is depreciated so as to maintain level return requirements under both recovery tests. The interest and dividends are paid in full each year, including the year of construction.

RECOVERY METHODS

I. The CWIP is included in the rate base during the year of construction and a full recovery of the capital costs provided during the year of construction.

II. The CWIP is excluded from the current rate base and the capital costs are accumulated as AFUDC and deferred for future recovery. This requires an added $100 of financing in year one to pay the interest and dividend costs. The ratios and cost rates are assumed to be the same as the initial financing.

The tax benefits of the interest payments during the construction year are deferred and claimed through depreciation over the property life.

CONCLUSIONS

The total revenues required under the Method I approach (CWIP in rate base for current recovery of financial costs) are considerably smaller than Method II (AFUDC approach). On a present value restatement, the revenue requirements are the same under either method.

	REVENUE REQUIREMENTS	
	TOTAL	Present Value
I. CWIP	$2,590,830	$1,358,490
II. CWIP Excluded	2,736,080	1,358,500

COMPARISON OF CWIP RECOVERY METHODS

METHOD I - CWIP INCLUDED IN RATE BASE FOR CURRENT RECOVERY

OF CONSTRUCTION FINANCING COSTS

PERIOD	RATE BASE ($000)	REVENUE REQUIREMENTS DEPRE. ($000)	TAXES ($000)	RETURN ($000)	TOTAL ($000)	PRESENT VALUE OF REV. REQ. ($000)
1.	1,000.0	0	38.33	100.0	138.33	138.33
2.	1,000.0	50.0	38.33	100.0	188.33	171.21
3.	950.0	50.0	36.42	95.0	181.42	149.93
4.	900.0	50.0	34.50	90.0	174.50	131.10
5.	850.0	50.0	32.58	85.0	167.58	114.46
6.	800.0	50.0	30.67	80.0	160.67	99.76
7.	750.0	50.0	28.75	75.0	153.75	86.79
8.	700.0	50.0	26.83	70.0	146.83	75.35
9.	650.0	50.0	24.92	65.0	139.92	65.27
10.	600.0	50.0	23.00	60.0	133.00	56.40
11.	550.0	50.0	21.08	55.0	126.08	48.61
12.	500.0	50.0	19.17	50.0	119.17	41.77
13.	450.0	50.0	17.25	45.0	112.25	35.77
14.	400.0	50.0	15.33	40.0	105.33	30.51
15.	350.0	50.0	13.42	35.0	98.42	25.92
16.	300.0	50.0	11.50	30.0	91.50	21.90
17.	250.0	50.0	9.58	25.0	84.58	18.41
18.	200.0	50.0	7.67	20.0	77.67	15.37
19.	150.0	50.0	5.75	15.0	70.75	12.73
20.	100.0	50.0	3.83	10.0	63.83	10.44
21.	50.0	50.0	1.92	5.0	56.92	8.46
TOTAL		1,000.0	440.83	1,150.0	2,590.83	1,358.49

COMPARISON OF CWIP RECOVERY METHODS

METHOD II - CWIP EXCLUDED FROM THE RATE BASE

PERIOD	RATE BASE ($000)	REVENUE REQUIREMENTS DEPREC. ($000)	TAXES ($000)	RETURN ($000)	TOTAL ($000)	PRESENT VALUE OF REV. REQ. ($000)
1.	0	0	0	0	0	0
2.	1,100.0	55.0	44.08	110.0	209.08	190.07
3.	1,045.0	55.0	41.98	104.5	201.48	166.51
4.	990.0	55.0	39.87	99.0	193.87	145.66
5.	935.0	55.0	37.76	93.5	186.26	127.22
6.	880.0	55.0	35.65	88.0	178.65	110.93
7.	825.0	55.0	33.54	82.5	171.04	96.55
8.	770.0	55.0	31.43	77.0	163.43	83.87
9.	715.0	55.0	29.33	71.5	155.83	72.70
10.	660.0	55.0	27.22	66.0	148.22	62.86
11.	605.0	55.0	25.11	60.5	140.61	54.21
12.	550.0	55.0	23.00	55.0	133.00	46.62
13.	495.0	55.0	20.89	49.5	125.39	39.95
14.	440.0	55.0	18.78	44.0	117.78	34.12
15.	385.0	55.0	16.67	38.5	110.17	29.01
16.	330.0	55.0	14.57	33.0	102.57	24.55
17.	275.0	55.0	12.46	27.5	94.96	20.67
18.	220.0	55.0	10.35	22.0	87.35	17.28
19.	165.0	55.0	8.24	16.5	79.74	14.34
20.	110.0	55.0	6.13	11.0	72.13	11.79
21.	55.0	55.0	4.02	5.5	64.52	9.59
TOTAL		1,100.0	481.08	1,155.0	2,736.08	1,358.50

CWIP - IN THE RATE BASE OR NOT?

A Presentation by Robert G. Towers,
Public Utility Rate Consultant

To the Iowa State Regulatory Conference
Iowa State University

May 22, 1980

Some of my friends in the automobile industry heard that I had been asked to talk to you today about the idea of permitting an investor-owned company to earn a current return on plant under construction. I told them that this was an idea that had already been given a great deal of thought by many of the people in this audience and that, indeed, there probably would be some people in the audience who had already decided that putting construction work in progress in the rate base was the proper thing to do. My friends seemed to be very interested.

I explained to them that for many years in the utility industry, the practice had been to exclude construction work in progress (CWIP) from the utility's rate base and that the practice had been called into question only in recent years, since about the time of the oil embargo in 1973. I said that ever since the embargo, many utilities have made persistent appeals to their regulatory commissions to include CWIP in their rate base. A number of reasons have been offered in support of the change. Foremost among the reasons advanced for the inclusion of CWIP in rate base has been the fact that, for the industry as a whole and individual companies in particular, the investment in CWIP relative to the investment in income-producing plant had increased. This was the result of a number of conditions--the high rate of inflation driving up the unit cost of new plant, the impact of changing conditions in fuel markets necessitating the conversion of existing generating equipment from one fuel to another, the requirement to adapt or sometimes replace existing plant to meet increasingly stringent environmental and safety regulations imposed by government, and, of course, the ever-present need to satisfy the requirements of the public for an essential service. At the same time that the industry's requirements for capital were on the increase, the industry experienced rising costs in its costs of capital and the high rate of price inflation affected operating expenses and made it more difficult for utilities to generate cash internally. In addition, it has been suggested that utility earnings are much less predictable ever since the oil embargo because of the efforts of consumers to adjust to the changing relationship of utility service costs to their incomes and other living costs. Conservation, it is claimed, has added uncertainty to earnings expectations and has complicated the process of utility planning for the future. My friends thought about this for a few minutes and then made the following request.

They asked me to take up a collection for the American automobile industry. The object of this collection is to allow the automobile industry to recover currently the carrying charges on its construction program. My friends were confident that most of you would be aware of the financial problems that the American automobile industry is now experiencing. But they thought that a quick review of the problems that their industry has encountered might be helpful in soliciting your support--particularly from those of you who believe that a utility's construction work in progress belongs in its rate base because of the utility industry conditions that I described just a moment ago. Like the utility industry, many of the American automobile industry's problems can be traced to the oil embargo in late 1973. Automobile users began to conserve, initially because of the scarcity of fuel and, later because of rising fuel prices. Sales of new automobiles declined. Initially this might have been a simple response to the uncertainties in the fuel market; eventually, sales were affected adversely by the increasing prices of automobiles and by the fact that existing automobiles were being used less, thereby extending their useful life.

The combined effect of consumer responses to changing conditions in the fuel markets and new government regulations requires drastic changes in the plant and equipment necessary to manufacture automobiles. Consumers are rejecting gasoline engines in favor of diesel engines at an unprecedented rate; they are rejecting large cars in favor of smaller, more efficient units and their interest in smaller cars has triggered major changes in automotive design--switching the driving wheels to the front of the car and developing ancillary equipment such as turbo-chargers to allow a reduction in the size of engines without a proportionate sacrifice in performance. At the same time consumers are expressing their new preferences, the government has become increasingly active in making demands on the automobile industry. Government regulations required the industry to make capital investments to improve the safety of vehicles, then to add pollution control equipment and, most recently, to meet progressively more demanding fuel efficiency goals.

Actually, government regulations affected both the product and the processes of the automobile industry. The industry was subject to the same safety and pollution abatement regulations in the operations of its manufacturing facilities as were applicable to the utility industry. Also, since the American automobile industry operates in the same economy as the American utility industry, its operating expenses were subject to the same upward pressure from inflation and its capital costs increased in the same way that these costs increased in the utility industry.

Then, as if all of these burdens were not enough, one of my friends said "In late 1979 the Financial Accounting Standards Board issued some sort of a statement which may require the automobile companies to capitalize interest during construction. Imagine what that will do to the "quality" of our earnings!" Parenthetically, I told him that the utility industry didn't have to worry about the FASB's Statement No. 34 requiring the capitalization of interest during construction. I have already heard utility officials invoke the utility exemption provided in the Addendum to APB Opinion No. 2. As you know, Addendum to APB Opinion No. 2 is the one which some utilities would like to forget about when commissions talk about such things as interperiod allocation of income taxes.

Now, my friends in the automobile industry recognize that there are some serious allocation problems involved in suggesting that each of you contribute, say, $15.00 this year, toward the carrying charges on their plant under construction. For example, some of you are not planning to buy a car over the next two or three years when the plant now under construction will be used to produce new automobiles. Indeed, some of you may belong to that growing group of people who are buying imported cars and may never recognition of a rateable portion of the plant investment as an expense of the accounting period. The accountant identifies the revenues and expenses associated with the units of production during the accounting period and recognizes each of these components in measuring the income earned. In regulation, revenues reflect unit charges which are established by the regulatory commission. Thus, to implement the matching principle the regulator must insure that the cost of service upon which the rates are based properly reflects the costs associated with the service benefits produced during the period. Since there are no service benefits produced by plant which is under construction, the costs associated with that plant should be excluded from the cost of service.

A second reason for objecting to the imposition of CWIP-related carrying charges on current consumers is that it violates what I refer to as the responsibility principle. There are two dimensions to this principle. One relates to the relative responsibility for the carrying charges among consumers; the other deals with division of responsiblities between consumers and investors.

I have already suggested that you might find it objectionable to pay the carrying charges on General Motors' CWIP if you were not intending to purchase one of their automobiles or if the carrying charges allocated to you were greater than the costs that you would incur if the carrying charges were deferred and paid as a part of the price of the product at the time of purchase. That objection is certainly valid in the utility sector. The troublesome construction requirements of electric utilities frequently are related to the construction of generating plant which, in turn, is a response by the utility to anticipated load growth. If the anticipated load growth is not uniform across the utility system then the allocation of CWIP carrying charges between jurisdictions and among customer classes on the basis of current rather than incremental demands is demonstrably wrong. The effect of such an allocation is to require customers whose load growth is below the system average to subsidize customers whose anticipated load growth exceeds the system average. The extremes of this misallocation include the situation in which a customer served during the construction period leaves the system at the time the plant goes into service. He contributes to the carrying charges but receives none of the service benefits. The opposite result is experienced when a customer not on line during the construction period becomes a customer at the time the plant goes into service. In between these extremes, there is an infinite number of discriminatory situations. For example, despite my best efforts to control the situation, I am currently heating enough water to shower three teenagers for a combined time of about 1½ hours per day. That makes me a large electric consumer. Hopefully, over the next three to five years, my consumption will decline as the children move away to college or adopt more conservative habits. If that is true, why should I be required today, on the basis of my present consumption, to pay the carrying charges on a generating plant to be used over a 30-year period beginning five years from now?

The distinction between the responsibilities of investors and consumers is particularly relevant in the regulated utility industries. As I perceive the relationship between ratepayers and a utility that is providing an essential service for which the consumer has no viable substitute, the utility and its investors are responsible for making the service available and accessible to the consumer, while the consumer is responsible for paying for the service rendered at rates which compensate the utility for the costs incurred in providing that service. The utility's responsibility stems from the grant that it received from the state to render an essential service as a virtual monopoly. The ratepayers' responsibility arises from a consideration of the equities involved. Obviously, the utility sought and received its authorization to render service with the understanding that it would be compensated for the cost incurred. This understanding typically is embodied in the applicable regulatory statutes.

The matching and responsibility principles are separate but they are intertwined and mutually supportive. For example, when I conclude that each customer class should be held accountable for the costs incurred by the utility to serve its group or conversely, that one customer class or generation should not be required to subsidize another class or generation, the conclusion reflects an application of both the responsibility and the matching concepts. In utility regulation, the concepts are implemented simultaneously by the application of what has become known as the used and useful standard. The used and useful standard is simple to apply and obviates the detailed and more subjective analyses that could be made to apply directly the matching and responsibility principles to a contested rate base item such as construction work in progress. The used and useful standard holds that costs associated with facilities that are neither used nor useful in rendering service to customers during the test year should be excluded from the rate base upon which the utility is entitled to earn a return in the context of test year sales. By definition, CWIP is neither used nor useful in rendering service and, therefore, it should be excluded from rate base.

I am confident that most of you are at least generally familiar with the fact, that when CWIP is not included in a utility's rate base, its investors recover the carrying charges incurred during the construction period through the capitalization of an allowance for funds used during construction (AFUDC). Thus, utility investors are made whole whether or not CWIP is included in rate base. While I will not elaborate on either the concept or the practice of capitalizing AFUDC, because I think it is unnecessary for this audience, I do want to comment on the criticism, often levied by the proponents of CWIP in the rate base, that the increment of reported earnings attributable to AFUDC is "inferior" to other earnings. Generally, these other earnings which are often erroneously referred to by these critics as "cash earnings", consist mainly of utility operating income.

My first observation is that the criticism stems from the unique manner in which the cost of financing CWIP is reflected in a utility's income statement. A utility incurs labor and material costs both for construction and operations and, in measuring its operating income, it disregards the labor and materials costs associated with construction. In contrast, the carrying charges associated with both operations and construction are deducted in measuring net income. Only by reversing a portion of these deductions--that is, by deducting the AFUDC associated with borrowed capital from interest charges and by recognizing the equity component of AFUDC as other income--are these overstated expenses reduced to a level that can properly be associated with current operations. Thus, "earnings" measured without recognizing AFUDC is simply not a bona fide measure of income for the period.

Secondly, in terms of "quality", I suggest that AFUDC earnings which arise from a regulatory commission's decision to exclude CWIP from rate base might be superior to the allowed utility operating income. There is no guarantee that the utility will earn the allowed operating income. The AFUDC component of net income is guaranteed. Moreover, it is unlikely that it will not be recovered through depreciation over the life of the facility. Finally, knowledgeable investment analysts surely must recognize that a utility's ability to generate currently both cash and pre-tax earnings coverage is enhanced if it has capitalized AFUDC in the past.

In one way or another, I believe that I have now touched on the principal reasons that I am opposed to the inclusion of CWIP in a utility's rate base as a general ratemaking policy. I have spent a considerable amount of time to reach the simple point that CWIP should be excluded from a utility's test year rate base because it is not used or useful plant. I hope that in doing so, I have made it clear to you that there is a lot of substance to the used and useful standard. My experience has been that, too often, the used and useful standard is treated as nothing more than a piece of conventional wisdom that is no longer relevant. Ironically, some of the responsibility for the degradation of the used and useful standard must be borne by its proponents. It has been abused. For example, there are instances in which appropriate test year adjustments to plant in service are opposed on the grounds that the plant was not actually used and useful during the historic test year. But the used and useful standard does not prohibit appropriate adjustments for known and measurable changes. When a major component of plant is placed in service during or shortly after the end of the historic test year, it is appropriate to annualize its impact on rate base if its annualized effect on income can also be determined with reasonable accuracy.

As rate analysts and regulators, we must recognize that we will frequently be called upon to resolve issues in which equally sound ratemaking standards seem to dictate different results. It is in such situations that one must exercise an intelligent judgement based upon all of the facts and circumstances. In the case of the test year transfer of plant from CWIP to plant in service, the competing ratemaking standards are:

(1) the used and useful standard which, initially at least, seems to call for the exclusion of the plant adjustment, and

(2) the concept that rates should be based on a cost of service which reflects current, known, and measurable costs.

But the issue can be resolved without violating either principle if one recognizes that the used and useful standard is a manifestation of the matching and responsibility principles. These principles will not be violated if both rate base and income are properly adjusted.

On the other hand there are instances in which both analysts and regulators have been unnecessarily reluctant to apply the used and useful standard to plant which is "in service" only because of accounting regulations. Plant investments which represent substantial excess capacity and investments in plant which is not usable because of technical or legal impediments should be treated like CWIP for ratemaking purposes. Perhaps it would be more correct to refer to these types of investments as plant held for future use but I generally discuss their ratemaking treatment as CWIP because, in many instances, the resumption of at least a partial capitalization of AFUDC may be justified.

To recap, I submit that the used and useful standard is both sound and relevant and that its application calls for the exclusion of CWIP from rate base as a matter of general ratemaking policy.

That statement brings me to the $64 question. Are there circumstances in which it might be appropriate to deviate from the general ratemaking priniciple by allowing CWIP or some portion of it to be included in a utility's rate base? The answer is yes. It is conceivable that a combination of conditions could be present for a utility in which the application of sound regulatory principles, including the exclusion of CWIP from rate base, would create an untenable situation for the utility and its customers by violating constraints on the utility which are not explicitly considered in the ratemaking process. There may be occasions--generally for short periods of time--in which a utility's allowable and otherwise compensatory earnings would be an inadequate multiple of its fixed charges to allow it to continue to finance plant construction in a manner which would maintain a reasonably balanced capital structure. I want to emphasize that I am <u>not</u> referring to a condition in which a utility's earnings coverage of fixed charges is inadequate, in someone's judgement, to maintain a predetermined bond rating. I am referring to a situation in which the utility's coverage is below the minimum coverage specified in its existing bond indenture and/or its articles of incorporation as a prerequisite to selling new securities. As you know, the typical electric utility bond indenture requires the utility to demonstrate that its recent earnings, before income taxes and including a limited amount of below-the-line "other income", are at least two times the annualized interest on its long-term debt, including the proposed new issue.

Under such conditions, and assuming that the utility is engaged in a construction program that the regulatory commission finds to be necessary, the commission has two or, perhaps, three ways in which it can increase the utility's pre-tax earnings for coverage purposes. It can increase the return on equity capital or it can include all or a portion of CWIP in the utility's rate base. A third possibility is to implement or expand income tax normalization if the utility is regulated on a flow-through basis. Of the three methods for increasing pre-tax earnings, the inclusion of CWIP in the utility's rate base is the least undesirable. Granting the utility a return on equity in excess of its cost of equity capital would enrich the common stockholders unjustifiably. The excess earnings would never be returned to rate-payers through cost of service reductions. In contrast, the inclusion of CWIP in rate base has the compensating advantage of reducing the cost of plant and the utility's cost of service in the future. While this "advantage" is inadequate to support the practice as a general ratemaking principle, it does make it clearly preferable to granting the utility an excessive rate of return on its equity capital. The inclusion of CWIP in rate base also is preferable to income tax normalization because there are fewer problems involved in using it as a temporary measure to grant extraordinary rate relief. Moreover, the CWIP allowance can be tailored to provide exactly the earnings coverage that is required. Furthermore, because the financial crisis is almost always related to a large construction program, it is logical to resolve it with a CWIP allowance.

I emphasize that this treatment of CWIP--to avoid a situation in which the utility would be unable to finance needed construction--is extraordinary and should be recognized as a temporary departure from the general ratemaking principle of excluding CWIP from rate base. It should not be perceived as an abandonment of that principle. The inclusion of a portion of CWIP in a utility's rate base to avoid a financial crisis is simply an acknowledgment of the legal and practical requirements to establish rates which will maintain the utility's ability to finance so that it can satisfy its obiligation to provide continuous and reliable service to ratepayers.

I said that there were generally three adjustments to a utility's cost of service that could be made to increase its earnings coverage of fixed charges to a level that would permit it to finance its construction program. That does not mean, however, that the financing problem could not be resolved in whole or in part in some other way. It seems to me that the threshold question always should be: Is the construction necessary and timely? Unfortunately, this is a question which simply cannot be answered in the limited time that is generally available to a regulatory commission which is confronted by a utility with an imminent deficiency in its indenture coverage. Accordingly, as a utility's construction program grows, it becomes increasingly important for the regulatory commission to monitor its construction plans.

A second question which needs to be answered is: Given the construction program, is the utility's proposed financing reasonable and, can it be modified to avoid the alleged crisis. This too is a question that can be discussed more intelligently if the commission has been monitoring the utility's financing plans. Specifically, some of the alternative methods that should be explored to avoid or mitigate the crisis are: If indenture coverage is the problem, does the utility need to sell long-term debt under its existing indentures or, in the alternative, should it be using more equity capital, increasing its short-term debt as a temporary measure, or selling subordinated bonds under a new less restrictive indenture. Another possibility, is for the utility to seek a change in its existing indenture requirements. But that generally would require a substantial amount of time to obtain the approval of a large percentage of its existing bondholders and, undoubtedly, it would require the utility to increase the interest rate on its outstanding bonds. Incidentally, when I suggested that the utility might finance a larger portion of its construction requirements with equity capital, I had in mind that that could be achieved either by selling new equity capital or by retaining a larger proportion of its equity earnings. In other words, the company's dividend policy should be examined.

A third alternative to cost of service adjustments is to require ratepayers to participate directly in the financing of the plant in a manner which is more cost-effective than the cost of service adjustments. Specifically, one could implement a surcharge whereby all customers would make a refundable "advance in aid of construction" to the utility through a surcharge. The principal advantage of refundable advances is that the cash which they generate is not taxable income to the utility. Thus, unlike the alternative cost of service adjustments which require the customer to pay two dollars to the utility to increase the utility's cash flow by one dollar, the one dollar improvement in the cash flow can be achieved with advances at a cost of only one dollar to the consumer. Stated differently, if the ratepayer is to pay the utility two dollars, the utility's cash flow is increased by two dollars if advances are used, but the utility's cash flow is only increased by one dollar if CWIP is included in its rate base.

Customer advances would provide a new source of capital to the utility thereby reducing its need for capital in other forms and reducing its interest charges to the extent that the advances displace debt. However, because advances do not represent income, they would not, in the absence of a modification of most existing indentures, enhance the earnings component of a utility's earnings coverage of fixed charges. Also, there would be administrative costs involved with any program of advances and the plan would have to be carefully developed in order to satisfy the Internal Revenue Service that the advances are not revenue derived from current service.

My knowledge of efforts to implement advances programs for two utility companies--both here in Iowa--suggest that the following elements are essential to an equitable plan having a reasonable chance of receiving favorable treatment from the Internal Revenue Service:

(1) The aggregate amount of the advances should be directly associated with plant under construction; the surcharge should be derived from anticipated construction costs.

(2) The advances should be mandatory; that is, the surcharge should be imposed on all customers.

(3) The plan should establish an accounting procedure whereby the refundable advances made by each customer can be determined at any time and to insure that each customer is ultimately refunded the full amount of his advances.

(4) The advances should be made by the customer while the subject plant is under construction; refunding of the advances should begin at the time the plant is placed into service.

(5) The refund period should be relatively short to further insure that the customers who made the advances will receive the refunds.

(6) The advance required of each customer should not be directly related to service currently rendered to the customer. I suggest that the amount of the advance be a uniform amount per month for all customers within a class or subclass. A uniform surcharge would also simplify the accounting procedures for advances.

(7) Interest should be paid on the advances; the utility should accrue the interest and pay it to the customer along with its refund of the principal.

Following these procedures, the company would continue to capitalize AFUDC on the associated CWIP at a rate which recognizes the interest paid on the advances. Interest on the advances could be accrued as long as an unrefunded balance existed, in which case the advances would not be deducted from rate base when the associated plant was placed into service. Alternatively, the accrual of interest could cease when the plant is placed into service. In the latter case, the unrefunded advances and accrued interest would be deducted from the utility's rate base until they are exhausted through the refunding procedure.

I mentioned that there were two Iowa utilities for which customer advances programs had been considered. One of these Companies--Iowa Southern Utilities Company--has implemented a plan that it developed jointly with the Iowa State Commerce Commission. I understand Iowa Southern has paid no income taxes on the $4.7 million which it had collected through the end of 1979 as refundable customer advances but that the taxability of these collections has not been finally resolved with the IRS.

As with many other questions raised in regulation, the question "CWIP--In the Rate Base or Not?" cannot be answered with a simple, unqualified yes or no. I hope that my remarks today have led you to that conclusion as well. However, my real objective was to put the question in a proper perspective so that it could be answered as follows: Construction work in progress should not be included in a utility's rate base as a matter of ratemaking policy. However, conditions may arise from time to time in which a utility would be unable to finance plant that is essential to the satisfaction of its public service obligations without some form of extraordinary rate relief. If, after exhausting all of the alternatives for avoiding the impending crisis, it is clear that a cost of service adjustment must be made, the inclusion of CWIP in the utility's rate base is preferable to alternative cost of service adjustments. But this extraordinary rate relief should be limited both in amount and duration to no more than that which is necessary to permit the utility to avoid its financing crisis. Finally, I would urge utilities and regulators everywhere to consider and promote the development of standby plans for refundable, tax-free customer advances to be implemented if and when the need arises.

Thank you.

TWENTY-FIRST SESSION, Thursday, May 22 - 3:00 p.m.

Concurrent Session H-3

FINANCING NUCLEAR DECOMMISSIONING

CHAIRMAN: G. Robert Faust, Divisional Vice President
Gilbert Asscoiates, Inc.
Board of Directors, Iowa State Regulatory Conference

SPEAKERS: John S. Ferguson
Senior Vice President
Middle West Service Company

Preston A. Collins
Principal Consulting Engineer
Gilbert Associates, Inc.

Nicholas S. Reynolds, Partner
Debevoise & Liberman

FINANCIAL ASPECTS OF POWER REACTOR DECOMMISSIONING

John S. Ferguson
Senior Vice President
Middle West Service Company
Dallas, Texas

As a consultant to electric utilities the author often becomes involved in the development of policy for capital recovery and in the determination of depreciation rates that will implement the policy. Utility capital recovery is controlled by generally accepted depreciation accounting practices and by regulatory commission accounting rules and, as a result, can differ significantly from engineering economics. Those involved with decommissioning of power reactors should be aware of the depreciation accounting and regulatory framework that dictates capital recovery requirements, whether their involvement is related to engineering economics or capital recovery. This presentation will define that framework, point out several significant implications (particularly tax), describe several conforming capital recovery methods, and discuss current activities of the Nuclear Regulatory Commission (NRC) relative to financial assurance that may alter how utilities and their regulators are allowed to react to the framework.

REVENUE REQUIREMENT ISSUES

Utility financial managers and regulators are concerned with the revenue requirement side of nuclear decommissioning; the managers, because they must have the cash available to accomplish decommissioning, and the regulators, because customers are the source of this cash. The revenue requirement components of concern relate to depreciation expense and rate base. These components are directly related because the accumulated depreciation reserve is a negative component of rate base.

The engineering economist thinks in terms of, and makes decisions, based on present worth. Since capital recovery for decommissioning becomes an issue in a service rate case, the utility accountant and regulator think in terms of, and make decisions, based on the revenue requirements generated within the context of that case. While the regulator may not always be presented with all of the revenue requirement components affected by decisions concerning the method of capital recovery, most recognize that there are significant tax aspects involved. The tax aspects may not be well understood by the engineering economist, and be excluded from his analysis.

As will be apparent later in this discussion, present value concepts may present a different picture of what is best for the customer than presented by the revenue requirements. While there is room for discussion of just what is significant to the customer, the role of a regulatory consultant requires that the author consider and evaluate revenue requirements.

ACCOUNTING AND REGULATORY FRAMEWORK

Depreciation accounting is an allocation process whereby consumption of physical assets is recognized in the income statement of a business enterprise. The matching principle that is basic to accounting requires that depreciation provisions match, to the extent possible, the pattern of consumption of assets. The purpose of depreciation expense is to provide full recovery of invested capital, and net salvage to be incurred at the time the facilities are decommissioned, over the expected life of the facilities constructed with that capital from those customers receiving benefits from the facilities.

The Uniform System of Accounts prescribed for electric utilities by the Federal Energy Regulatory Commission and followed by most utilities states that depreciation "as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities. Service value means the difference between original cost and net salvage value of electric plant."

There are three essential aspects to the determination of the depreciation rates; the amount of capital to be recovered; the period of time for recovery; and the pattern of recovery. Of major concern here are the determination of the amount to be recovered and the significance of the patterns inherent in several methods of recovery. Table I shows the formulae for the whole life and remaining life rate methods of calculating book depreciation rates. Decommissioning cost is recognized in the net salvage factor in these formulae. Since nuclear plant cost of removal exceeds gross salvage, net salvage is negative. Net salvage in these formulae is expressed as a percentage of the original construction cost (100) of the facility. Thus if the average service life is 10 years and salvage 0%, the rate is 10%, whereas if the salvage is negative 50%, the rate is 15%, an increase of 50%.

An aspect of capital recovery economics that is not universly understood is the fact that depreciation accounting practices and regulatory commission rules require that the net salvage to be either received or incurred at the end of life (at the price level at that time) is what must be built into the depreciation rates. It is not easy to estimate the decommissioning cost today, yet we must attempt to estimate when the cost will be incurred and the price level that will exist at that time. Even though it is difficult to do, the accounting and regulatory framework requires that expenditure timing and price level be determined.

REGULATORY CONSTRAINTS

Regulatory bodies are political entities and, whether we like it or not, make political decisions. Regulators have a responsibility to ensure that the utilities are financially viable, as that is the only way adequate service can be provided to customers. However, regulators have a revenue requirement bias that causes them to like things that decrease service rates to customers and to not like things that increase them. Since negative salvage (decommissioning cost) increases service rates, regulators don't like it. Many regulators have not faced up to the need to build sufficient negative net salvage into depreciation rates to adequately provide for decommissioning, and, until recently, they have had some fairly logical reasons for doing so. The first really useful decommissioning cost estimates did not start appearing until late 1976. Therefore, regulators were able to state that they recognize the need, but don't have an adequate cost estimate to use as the basis for setting the depreciation rates. Regulators no longer have this excuse. The utility industry also had a tendency to ignore the issue, which may be a factor in developing a serious concern at the NRC for the adequacy of the financial assurance aspects of the decommissioning power reactors.

Their revenue requirement bias will cause particular concern to regulators in jurisdictions that have opted to flow current tax savings through to customers. Decommissioning costs are not deductible for tax purposes until spent, so these jurisdictions must either reverse their position or allow future customers to reap the tax benefits of the expenditures. It will be interesting to watch their reaction when they better understand the capital recovery requirements of nuclear decommissioning. Each of the capital recovery methods discussed later has a distinctive revenue requirement pattern expected to evoke a particular regulatory response.

DECOMMISSIONING REGULATIONS

The present decommissioning regulations were originally promulgated by the Atomic Energy Commission and are contained in Sections 50.33 (f) and 50.82 of 10 CFR Part 50. These regulations require applicants for power reactor operating licenses to demonstrate that they have the financial integrity to meet operating costs as well as the estimated costs of permanently shutting down the facility and maintaining it in a safe condition. Specific decommissioning plans for nuclear power plants are not currently required until the licensee seeks to terminate his operating license. Should license termination be desired, Section 50.82 requires that the licensee provide the NRC with information on the proposed procedures for disposal of the radioactive material, decontamination of the site, and assurance of public safety. The proposed plan requires approval. Regulatory Guides have been issued to describe methods acceptable to the NRC staff for implementing regulations and spell out techniques used in staff evaluations, but are not substitutes for regulations and do not have the force of law.

FINANCIAL ASSURANCE

Utility financial managers and regulators are concerned about the availability of the funds required for decommissioning when the decommissioning process must occur. If a delayed removal process is selected for accomplishing the decommissioning, it makes sense to have cash available at the end of plant life that can be invested to provide earnings that will reduce the amount that must be collected from customers. Investing could also be done as the collections are made, which would further reduce the amount to be collected from customers. Capital recovery funds collected from customers have historically been reinvested by the utilities, reducing the magnitude of their future borrowings. If collections are invested as they are received, use of these funds may be denied, which is a serious deterrent to a utility supporting an external funding method. If collections are invested at the end of plant life, the utility must raise the cash for setting up the fund at that time, which may also be a problem.

Fund availability is an important issue. Cash is required to carry out the decommissioning process. Whether invested internally or externally, fund availability will depend on the ability to turn the investments into cash. This ability is greatly enhanced by competent regulation that ensures a financially sound ongoing operation. External funding has been suggested, and has been adopted in Pennsylvania, where State bonds are the required investment. Recent experiences in neighboring states should bring the degree of financial assurance from tax exempt securities into question. Will taxing power or earning power provide the highest degree of financial assurance?

Single plant organizations and situations where public entities, or entities under different regulatory jurisdictions are partners are cause for concern on the part of regulators, owners of single plant organizations, and partners in nuclear units, as to assurance of fund availability. The current activities of the NRC relative to assuring that funds will be available when needed will be discussed later.

SIGNIFICANT ONGOING ACTIVITIES

The NRC is currently reevaluating its policy toward the decommissioning of nuclear facilties and is expected to amend its regulations. Current regulations and guidelines have grown up in reaction to specific situations and are confusing, as well as incomplete. Workshops for purposes of keeping state agencies current on the progress of the reevaluation and for obtaining agency input were held by the NRC in the Fall of 1978 and again in the Fall of 1979. The 1979 Workshop was very significant to these discussions, as this was when the NRC staff first presented the results of their analysis of the financial assurance aspects of decommissioning. The NRC staff and the state agencys have both stressed the need for flexibility in any regulations concerning financial assurance, but draft NUREG-0584, the results of the staff analysis, was widely interpreted as heralding a regulatory requirement for the prepayment method of capital recovery. Prepayment would require holding marketable securities sufficient to pay for premature decommissioning. In addition to greatly increasing utility borrowing, the prepayment approach is the most costly for customers. In a February 22, 1980 letter to the NRC, the Utility Decommissioning Group presented figures for the nuclear plants of five members that indicate the present worth of the revenue requirements for prepayment varies from 2.4 to 13.6 times that for negative net salvage depreciation.

As part of its policy reevaluation, the NRC is currently engaged in several projects that will result in cost estimates for actual facilities, including both BWR and PWR generating stations. The PWR study covers the Trojan Plant in Oregon.

Congressional hearings in 1977 covered the lack of regulations for decommissioning and the Government Accounting Office (GAO) issued a report saying the federal government needs to develop a strategy for decommissioning. The GAO report also pointed out that the true cost of nuclear power is not being reflected in utility prices because decommissioning costs are not included, an issue about which the Securities and Exchange Commission (SEC) also became concerned. SEC Staff Accounting Bulletin No. 19 effective January 13, 1978 required utility companies with nuclear generating plants to disclose the estimated costs of dismantling or decontamination, and whether provision for these costs is being made in current operations and recognized in service rates. If such costs are not being currently provided for, disclosure is required of the reasons for omitting the costs and the potential impact on the financial statements.

It is highly likely that specific regulations concerning the technical, safety, and financial aspects of decommissioning power reactors will result from the current policy reevaluation being carried out by the NRC. Proposed regulations were expected to be ready for public comment in late 1980, but the program is running behind schedule.

DECOMMISSIONING COST ESTIMATES

The most detailed estimates currently available for decommissioning of nuclear plants are contained in the November 1976 report of the National Environmental Studies Project of the Atomic Industrial Forum, Inc. (AIF) <u>An Engineering Evaluation of Nuclear Power Reactor Decommissioning Alternatives,</u> and from the June 1978 report, <u>Technology, Safety and Costs of Decommissioning a Reference Pressurized Water Reactor Power Station,</u> prepared by Battelle Pacific Northwest Laboratory for the NRC. A similar report on a boiling water reactor at Hanford is due shortly. The AIF report covered decommissioning costs of model plants, while the NRC report covers an actual plant.

The AIF study contains cost estimates for several decommissioning alternatives and concludes:

1. There are no insurmountable technical problems in decommissioning to any degree, but considerations with respect to policy, planning, timing, costs, waste disposal, safety criteria, and regulatory aspects need further development.

2. Experience and cost data need to be accumulated so that the realistic planning for decommissioning can be instituted.

(Recovery of Nuclear Power Plant Decommissioning Costs, T. S. LaGuardia, 1977, Iowa State Regulatory Conference).

The NRC study evaluated and eliminated entombment as a viable approach to decommissioning and concludes:

1. Present technology can accomplish decommissioning.

2. Impacts from decommissioning on public safety are extremely small, even lower than from the operating plant.

(Prepared testimony of Richard I. Smith, Michigan Public Service Commission Docket U-6041)

These estimates and a number of recent site-specific estimates provide utility depreciation analysts a sound basis for determining adequate book depreciation rates for nuclear power plants. The need to select the most likely decommissioning alternative, and to balance the interests of utility financial managers, investors, customers, and regulators, complicates the efforts of the analysts. The needs of the depreciation analyst differ from those of the engineering economist, but much of the conventional wisdom surrounding nuclear decommissioning has been generated by economic analysis, not depreciation analysis. The discussion here is from the point of view of depreciation (and the financial manager and regulator) and identifies several problems that require solution.

In order to examine the impact of inflation, decommissioning cost estimates from the AIF report, recognizing contingencies (at 25%), cost savings due to multiple reactors at the same site, and the expenditure timing differences, are used to estimate actual costs to be incurred. Costs in the AIF report at 1975 price level were inflated to price levels at the time of expenditure using annual inflation rates of 7.5% through 1985, and 6% per year beyond. The calculations were made for a boiling water reactor (BWR) plant having two 1178-MWe units that would reach the end of their operating life January 1, 2015.

Figure 1 illustrates the decommissioning expenditure pattern for mothballing followed by complete removal after 104 years. During the year 2015, \$68.6 million would be spent in the initial mothballing process. Surveillance would begin in 2016, with an expenditure of \$5.2 million in that year, and would increase to an annual expenditure of \$2.2 billion in 2120. Complete removal would cost nearly \$150 billion. The impact of inflation on surveillance and removal cost is shocking, to say the least. The uncertainties surrounding a 104 year mothball period are formidable. These uncertainties aside, the impact of inflation and the difficulties of adequately providing for expenditures to be made far into the future make a good case for prompt removal.

ENGINEERING ECONOMICS VERSUS CAPITAL RECOVERY

Figure 2 allows comparison of the requirements for engineering economics studies with those of capital recovery. In this example decommissioning consists of three activities. The first, preparation for safe storage, would occur at the end of the life of the plant, and would cost \$7 million at the 1976 price level and with 5% annual inflation, \$38.6 million at the time it was spent in the year 2011. Annual surveillance would start at that time and would last 25 years, costing \$80 thousand per year at the 1976 price level for a total of \$2 million at that price level and, with 47.5 years of inflation, would average out to a total cost of \$20.3 million in

2023.5. Removal would occur at the end of the surveillance period, costing $16 million at the 1976 price level and $298.9 million at the time it would actually be incurred in 2036. A 9% present worth factor brings the costs to be incurred beyond 2011 back to an equivalent 2011 cost. The resulting total is $80.2 million. The annual annuity amount, using 9% interest is $372 thousand per year, and is used to calculate the depreciation component of fixed charges.

Several methods of capital recovery are available for collecting the funds required for decommissioning. If the collections were immediately invested in securities with after-tax earnings of 9% and if the collections were not considered as income to the utility, an annual collection of $372 thousand would be required. Thus, with these constraints (not possible under current income tax regulations) the capital recovery and the engineering economics approaches would be identical. As will be discussed later, other capital recovery methods exist that are less costly to customers.

The study illustrated on Figure 2 is not invented. It was found in the transcript of testimony before a state regulatory body in support of a depreciation rate to use in a feasibility study comparing nuclear and fossil fuel generation sources. Other engineering economics studies comparing the nuclear and fossil fuel alternatives have done such things as to use the same fixed charge rate for both alternatives and to assume that decommissioning costs were expensed as they were incurred. None of these approaches are consistent with the accounting and regulatory framework of depreciation.

Utility financial managers become concerned if they find that looking at decommissioning costs from a capital recovery standpoint results in significantly different numbers than looking at it from an engineering economics standpoint.

IMPLICATIONS OF INCOME TAXES

Income tax has a significant effect on the magnitude of the collections required from the customers. There are two tax issues. One is the inability to deduct cost of removal when calculating tax depreciation. Under current tax regulations, the actual expenditures for decommissioning would be deductible in the year incurred, provided the expenditures are made by a tax-paying entity having taxable income. Therefore, collections from customers would flow directly to income for tax purposes.

The second tax issue relates to earnings from invested funds. Figure 2 illustrated the reduction in collections from customers if they were invested as collected or at the end of plant life. The only way the earnings would be tax free is if the investments were in tax exempt securities.

The Black Lung Benefits Revenue Act of 1977 created a new type of tax-exempt trust to be used by coal operations to self-insure against liabilities for black lung benefits. The features of this Act of interest are the deductibility of operators' payments to the trust, the limitations on the trust's investments, the freedom from taxation of income received by the trust, and irrevocability of payments into the trust. The Act could be an applicable precedent for handling nuclear decommissioning funding.

The NRC staff states in the July and December, 1979 drafts of NUREG-0584 that the IRS has indicated payments into a trusteed fund might be tax deductible, provided:

1. All funds collected are immediately segregated and deposited in a blind trust immediately upon collection.

2. The blind trust cannot be reinvested in a utility's assets.

3. The fund is administered by people independent of the utility.

4. Over collections cannot be returned to the utility.

Such stringent restrictions on the recycling of funds can only serve to deter the utility industry from use of externally funded approaches. We will see later that there is another significant deterrent to use of external funding; it is more costly for the customers.

The utility industry is receiving a conflicting signal from the IRS concerning tax deductibility of payments into a trusteed fund. While the NRC says the IRS indicates payments into a trusteed fund might be tax deductible under certain conditions, a request for advance ruling on such a trust was withdrawn when an unfavorable ruling was felt to be forth coming.

Table II has been developed to illustrate the impact of taxability of fund earnings. The Table shows the magnitude of the investments required at the end of plant life to carry out several different processes of decommissioning a pressurized water reactor (PWR), under three different assumptions concerning the earnings of the fund and their taxability. The figures are from the AIF and NRC (PWR) studies, to which inflation and the impact of fund earnings have been added. Plan A assumes that the fund is invested in bonds earning 9% not subject to income tax. Plan B assumes that the fund is invested in the same bonds, but that they are subject to a 50% income tax. Plan C assumes that the fund is invested in tax-free securities with earnings exactly equal to future inflation. Under Plan A, which is not consistent with current tax law, the mothball-delayed removal process is the least expensive of the three decommissioning processes. Under Plan B, which is consistent with current tax law, the mothball process is the most expensive, having increased in cost by a factor of 12 due solely to the impact of income taxes. While Plan C is also consistent with current tax law, tax free securities are not currently earning enough to keep up with inflation. It is obvious that there are some very serious income tax consequences to decommissioning. Legislation will probably be required to correct them. The figures on Table II also make a case from prompt removal.

Until recently, the conventional wisdom, generated by engineering economics, was that mothball-delayed removal is the least expensive decommissioning process. The figures on Table II illustrate the probable source of this wisdom - failure to recognize capital recovery requirements and their attendant tax consequences.

CAPITAL RECOVERY METHODS

The most familiar method of capital recovery of the cost of decommissioning any type of facility is through recognizing net salvage in book depreciation rates. Regulatory approval of book depreciation rates containing adequate recognition of power reactor decommissioning costs is rare. Methods must be found to accomplish adequate capital recovery in a manner that will promote positive regulatory response.

Not only do such methods exist, they conform to depreciation accounting concepts and regulatory rules, have considerable precedence, and give the appearance of being cheaper than other alternatives. Four basic methods exist for capital recovery of power reactor decommissioning cost. They are:

1. Prepayment;

2. External Funding;

3. Internal Sinking Fund Depreciation; and,

4. Straight Line Depreciation

Prepayment and External Funding are not really methods of capital recovery, but for purposes of simplicity, all four methods will be refered to here as capital recovery. External Funding has been recommended in several jurisdictions, and has actually been adopted in Pennsylvania, where the funds collected from customers are required to be invested in state bonds. Proposals for funding of reserves are actually reverting to a depreciation provision technique that has fallen into disuse, called sinking fund.

Years ago, sinking fund was used as an interim step when the utility industry discontinued retirement and replacement accounting, but recent use by electric utilities is rare. Its purpose then was to minimize the increase in revenue requirements by calculating low depreciation expenses. Since the depreciation provision affects rate base, determination of the true impact of sinking fund methods on revenue requirements requires consideration of both the depreciation expense and return components. Low revenue requirements with the sinking fund method is a short-term phenomenon, as the combination of depreciation and return over the life of any item of property is higher than if straight line depreciation was used.

The appearance of low revenue requirements makes sinking fund methods appealing to regulators. The utility regulatory process allows sinking fund to be applied with either a depreciated or undepreciated rate base. The correct terminology for an undepreciated rate base is Sinking Fund and for the depreciated rate base is Modified Sinking Fund. Either way, the book reserve is the accumulation of the annual annuity amount collected from customers plus the annual interest on the reserve. If the annual interest <u>is not</u> included in revenue requirements, the accumulated provision <u>is</u>

not a deduction for the determination of rate base. If the annual interest is included in revenue requirements, the accumulated provision is a deduction for the determination of rate base.

Figure 3 illustrates the Sinking Fund Method. This example was developed to show what happens when the decommissioning process occurs in year 12, two years beyond the useful life of the property. Decommissioning cost in year 12 is $100. An interest rate of 5% was used in the calculations. The funds collected are assumed to be invested annually by a third party, requiring an annual annuity amount of $7.21. Over the ten-year period of collection, $18.60 is generated from the interest earned, and an additional $9.30 is earned in years 11 and 12 while the fund remains invested without annual collections. Anuual collections deposited in a bank account earning 5% would generate this picture. It is obvious that funds in a bank account would not be a deduction in determining rate base. Thus, the external funding method is what is technically known as Sinking Fund.

The concept illustrated in Figure 3 can also be used to describe the capital recovery component of Modified Sinking Fund. The only difference is that the customer is charged $7.21 each year plus that year's interest, and will receive a credit for the impact of the book reserve on the return component of revenue requirements. Thus, the normal regulatory view of the Internal Sinking Fund Depreciation method is what is technically known as Modified Sinking Fund. As internal funding has more components, its revenue requirements are not as easily visualized as for external funding. Internal Sinking Fund Depreciation can be implemented as either Sinking Fund or Modified Sinking Fund, but regulatory understanding might be better with the depreciated rate base (Modified Sinking Fund).

In order to compare the revenue requirements for the four capital recovery methods discussed earlier, a simplified example has been created from the assumptions shown on Table III. The resulting patterns of cumulative revenue requirements are shown on Figure 4. Calculations are made for four capital recovery methods: Prepayment has been eliminated and a modification of Straight Line Depreciation (inflation compounding) has been added. While the modification with inflation compounding is not consistent with the accounting and regulatory framework of depreciation, it is included because several state regulatory jurisdictions have adopted it. Inflation compounding recognizes only that inflation which has already occured. For example, with 10% inflation, decommissioning at a current cost of $100, and a 10 year life, the depreciation expenses for the first and second years would be as follows:

$$\text{First year} \quad \frac{\$100}{10 \text{ years}} = \$10$$

$$\text{Second year} \quad \frac{(\$100 \times 1.1) - \$10}{9 \text{ years}} = \$11.11$$

Straight Line Depreciation with Inflation Compounding appeals to regulators because it shifts a significant amount of the revenue requirements into the future, as shown by Figure 4. In this example, nearly half of the total revenue requirements are in years

29 and 30. External Funding is the most expensive, with Straight Line Depreciation with Inflation Compounding a close second. The internal methods are the least expensive. External Funding as plotted assumes the payments to the fund are net of the normalized tax benefit. If not normalized as paid, the annual fund payments would be larger and the tax benefit would be all in the final year. The total revenue requirements for Prepayment would be higher than any method shown on Figure 4. Variations of each are possible, but would not alter the fact that Prepayment would require customers to pay the most and Straight Line Depreciation the least.

In a rate case the capital recovery component of revenue requirements is most visable. That component is shown on Figure 5. Only the curves for the internal methods are shown, since they are the only true capital recovery methods. Comparison of Figures 4 and 5 illustrates the sensitivity of revenue requirements to the pattern of capital recovery. The fastest capital recovery generates the least total revenue requirements.

Figures 4 and 5 are based on a 30 year plant life, about the maximum that can be expected for a nuclear unit. The relationships between the methods do not change with shorter or longer lives, but the difference between Straight Line Depreciation and the other three methods increases with longer life because of its greater sensitivity to life. The revenue requirements for Internal Sinking Fund Depreciation are constant because of the method of determining the sinking fund interest rate. There have been several proposals, and some regulators have adopted use of interest equal to inflation. This would cause Internal Sinking Fund Depreciation to be a curved line, with total revenue requirements either higher or lower than on Figure 4, depending on the relationship between the internal interest rate and the rate of inflation.

The fact that the two sinking fund methods are straight lines and the other methods are curved lines makes it obvious that the relationships between the four methods would be different than shown on Figure 4 if the present value had been plotted.

The calculations for Figure 4 recognize that earnings from an external fund are subject to federal income tax unless investments are in tax exempt securities. If the assumption were made that fund earnings were not taxed, the external methods are still the highest and Straight Line Depreciation the lowest, but the spread is reduced. Taxation of fund earnings has more impact on the external methods than the internal. The examples on Figure 4 have been calculated assuming the tax benefit from decommissioning expenditures is normalized. If normalization is not allowed by regulators the distribution of revenue requirements over the life of the facility would be such that customers in the early years pay more and customers in existence at the time of decommissioning would reap a significant benefit.

REGULATORY REACTION

There are a number of good reasons why the financial assurance regulations that might be promulgated by the NRC should give federal and state service rate regulators flexibility in their ability to respond to the utility capital recovery needs; not the least of which are the patterns evident on Figures 4 and 5. Since Prepayment is the most expensive capital recovery method, regulators would be expected to have considerable reluctance toward its adoption. The high revenue requirements in early years makes regulators reluctant to adopt Straight Line Depreciation, even though in the long run it is the least expensive for customers. Given the political environment under which Federal and state service rate regulators function, Internal Sinking Fund Depreciation or Straight Line Depreciation with Inflation Compounding would likely be attractive. The regulatory adoptions of External Funding that have already taken place might not have occured if all options having regulatory precedent and meeting depreciation accounting principles had been made known.

In addition to being the most expensive for customers, Prepayment would add unneeded pressure on utility requirements for external financing. Available decommissioning cost estimates for the immediate removal process indicate a prepayment from $35 million to $85 million for each nuclear generating unit. Since there are currently about 70 such units licensed to operate in the United States, the financing requirement would vary from $2.5 billion to $6.0 billion. Viewed nationally, such borrowing merely shifts funds from one pocket to another, with significant financing costs being incurred in the process.

CONCLUSION

A thorough understanding by service rate regulators can only result in their reacting to decommissioning capital recovery requirements in a manner that provides the needed financial assurance. The electric utility industry is the only available source for this understanding.

The technical and safety aspects make nuclear generation controversial and politically sensitive. The impact of inflation and Federal income tax regulations on the capital recovery requirements for decommissioning further adds to the controversy. The following factors combine to make the capital recovery aspects a significant problem for utility financial managers and regulators.

1. The accounting requirements of capital recovery have evolved over a number of years and are well defined, both in terms of generally accepted accounting practices and regulatory precedent and law.

2. Utility financial managers must provide the cash necessary to accomplish decommissioning, and customers are the source of this cash.

3. Income taxes are a significant component of the revenue requirements evaluated by regulators in setting rates.

4. Engineering economic studies often fail to recognize capital recovery requirements, including income tax.

5. Regulators operate under political constraints that make it difficult for them to respond to increased revenue requirements.

6. The capital recovery component of the decommissioning cost revenue requirements is clearly visable in the service rate regulatory process.

The financial aspect of decommissioning nuclear generating plants is an issue whose time is come. The accounting and regulatory rules for handling the issue are in place. The capital recovery methods for handling the issue are also in place. The utility industry must learn to make the rules and the methods operate satisfactorily, recognizing the factors mentioned above.

TABLE I

ACCRUAL RATE CALCULATION

Whole life rates are calculated as follows:

$$\text{Rate} \quad = \quad \frac{100 - S}{ASL}$$

where S is net salvage in per cent, and ASL is average service life.

Remaining life rates are calculated as follows:

$$\text{Rate} \quad = \quad \frac{100 - S - \frac{R \times 100}{B}}{ARL}$$

where B is depreciable plant balance, S is net salvage in per cent, R is book depreciation reserve, and ARL is average remaining life.

FIGURE I

EXPENDITURE FOR

INITIAL MOTHBALL & REMOVAL AFTER COOLDOWN PERIOD

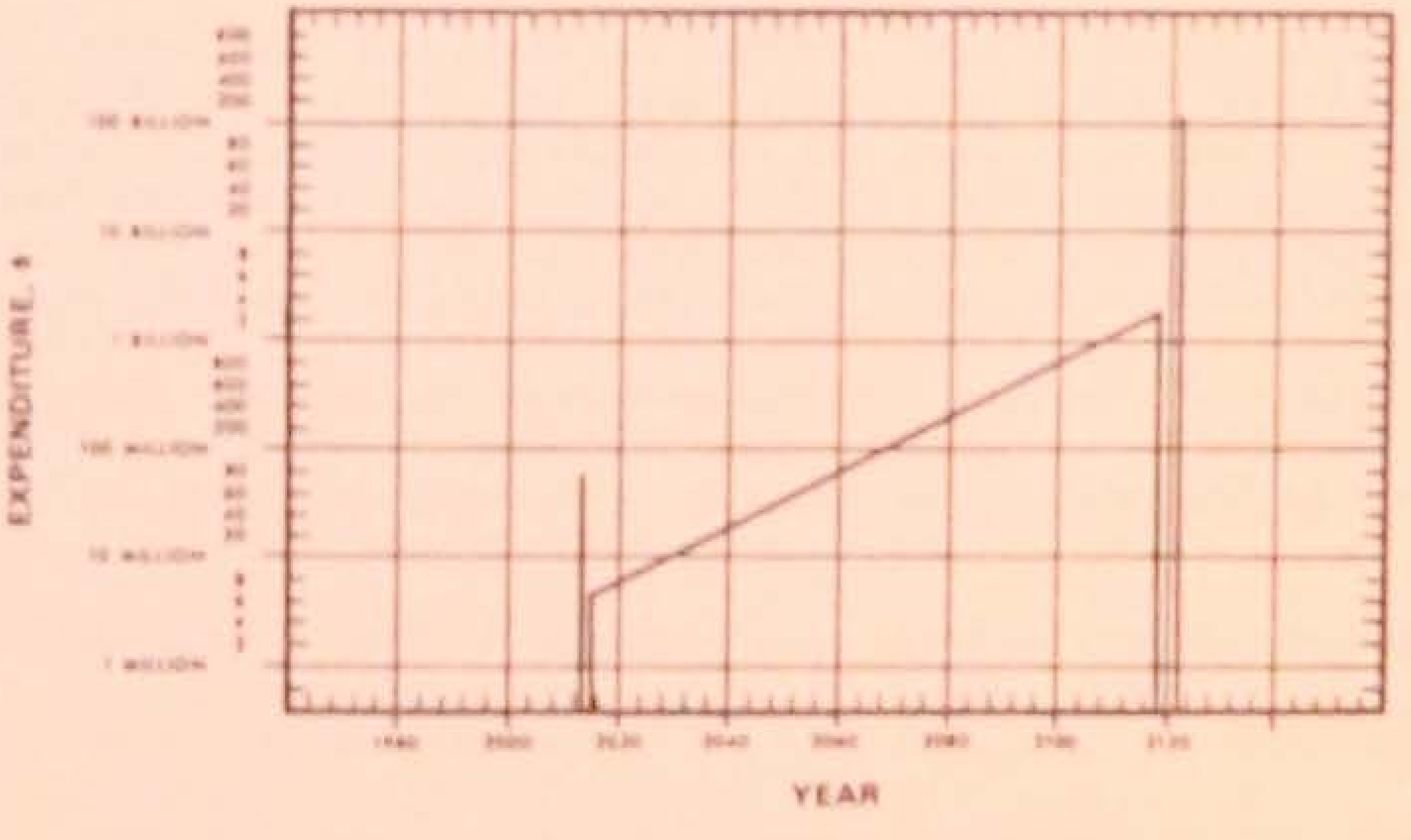


FIGURE 2

EXAMPLE OF ENGINEERING APPROACH TO DEPRECIATION

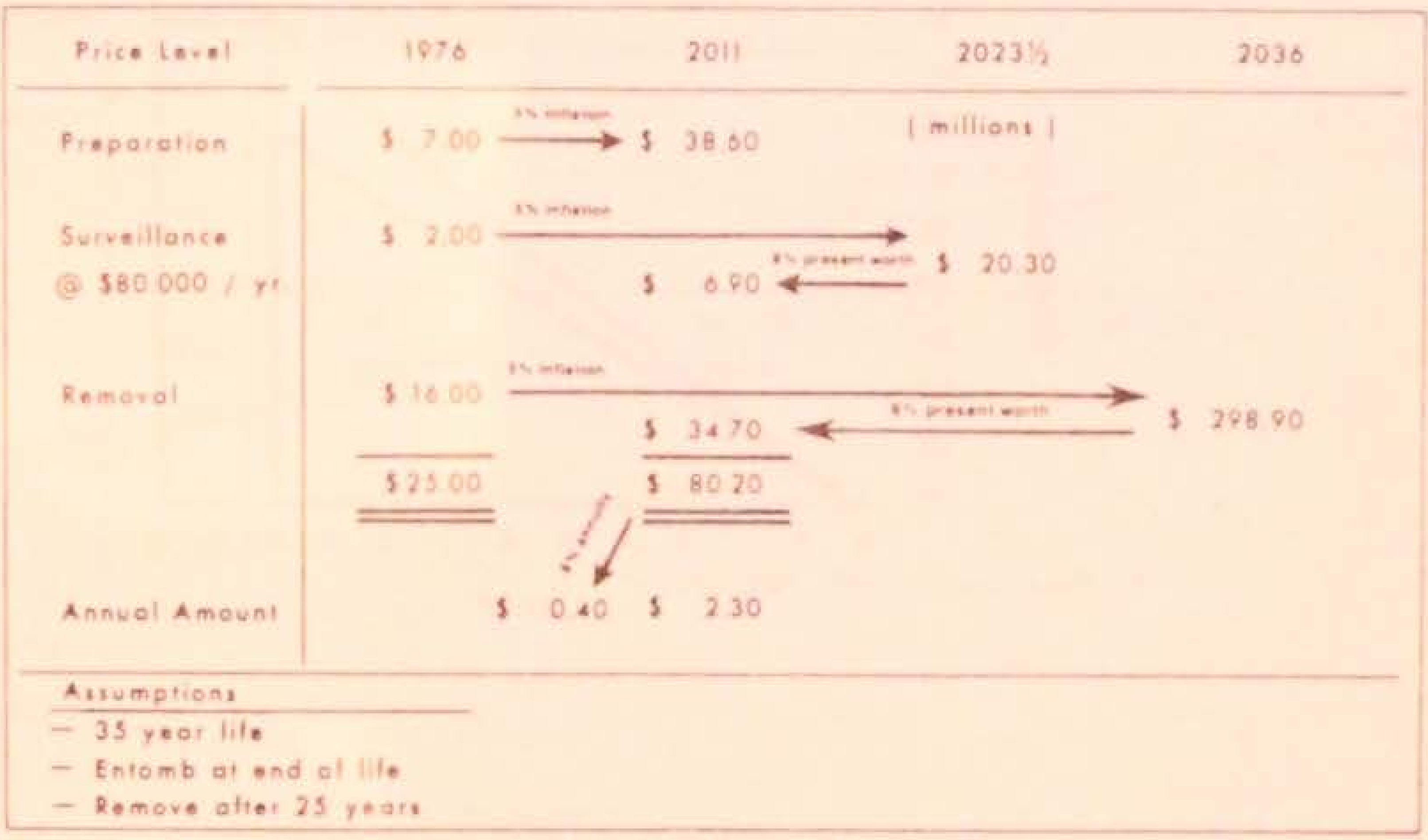


TABLE II

FUND REQUIRED AT END OF PLANT LIFE

	Plan A $1000	Plan B $1000	Plan C $1000
AIF Report			
Mothball-Delayed Removal	118,294	1,450,161	473,409
Entombment-Delayed Removal	138,910	1,133,649	370,945
Prompt Removal	365,660	414,962	397,593
NRC Report			
Delayed Removal			
100 year delay	160,253	1,556,619	502,539
50 year delay	213,115	801,877	465,735
30 year delay	293,937	720,922	516,220
Prompt Removal	368,937	418,681	401,157

FIGURE 3

MIDDLE WEST SERVICE COMPANY

DEPRECIATION PROVISION INVESTED ANNUALLY

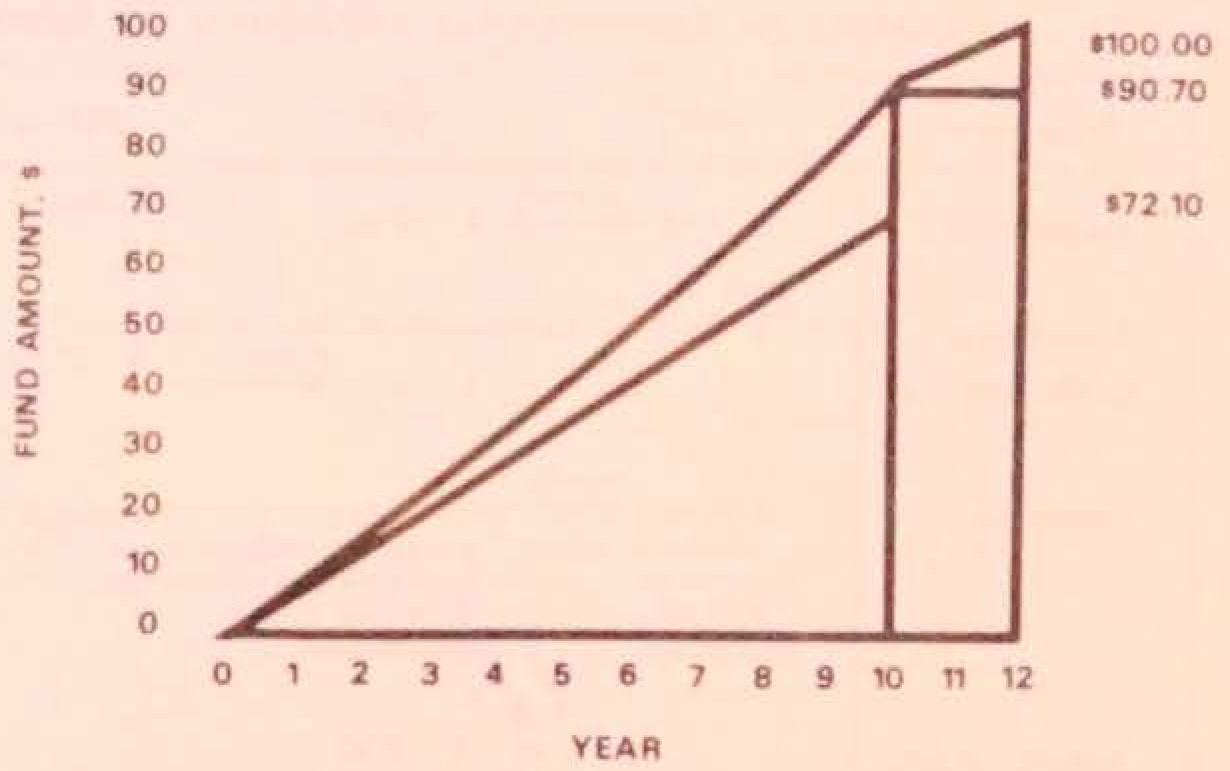


TABLE III

Assumptions

1) Plant life - 30 years

2) Immediate removal

<u>Process</u>	<u>Time</u>	<u>Cost</u>
Preparation	1 year	\$4 million
Removal	2 years	\$40 million

3) Inflation - 8%

4) External fund earnings - 10%

5) Capital

	Ratio	Cost
Debt	50%	11%
Preferred stock	15%	13%
Common stock	35%	16%
Composite		13.05%

6) Internal fund earnings - R-TIB

$$13.05 - (0.46)\ (0.50)\ (11) = 10.52\%$$

7) Income tax - 46%

8) Tax normalization

9) Instant regulation

10) Investing as collected for external methods

11) Investing at end of plant life for internal methods

12) Tax benefits available at time of investing

FIGURE 4

CUMULATIVE REVENUE REQUIREMENTS

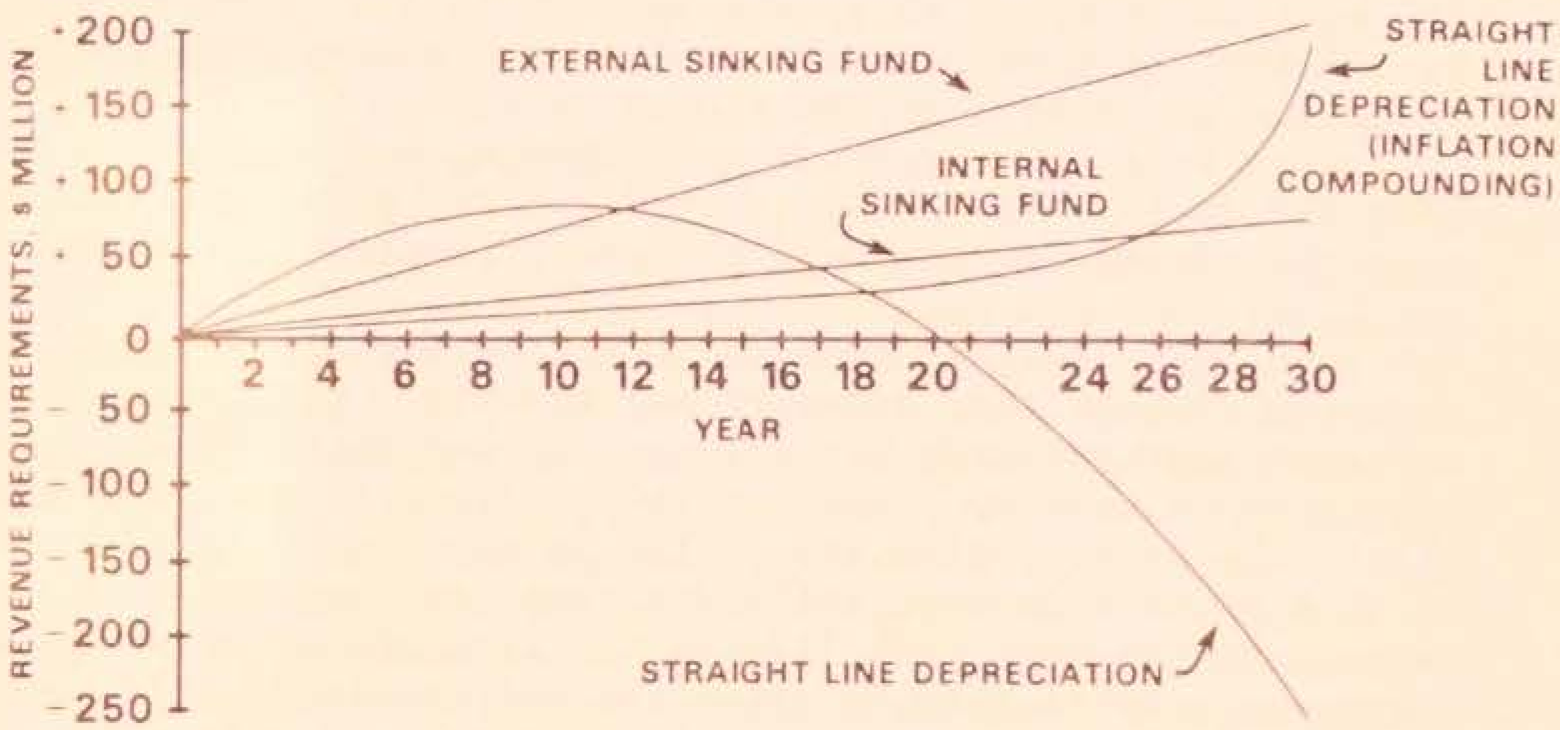
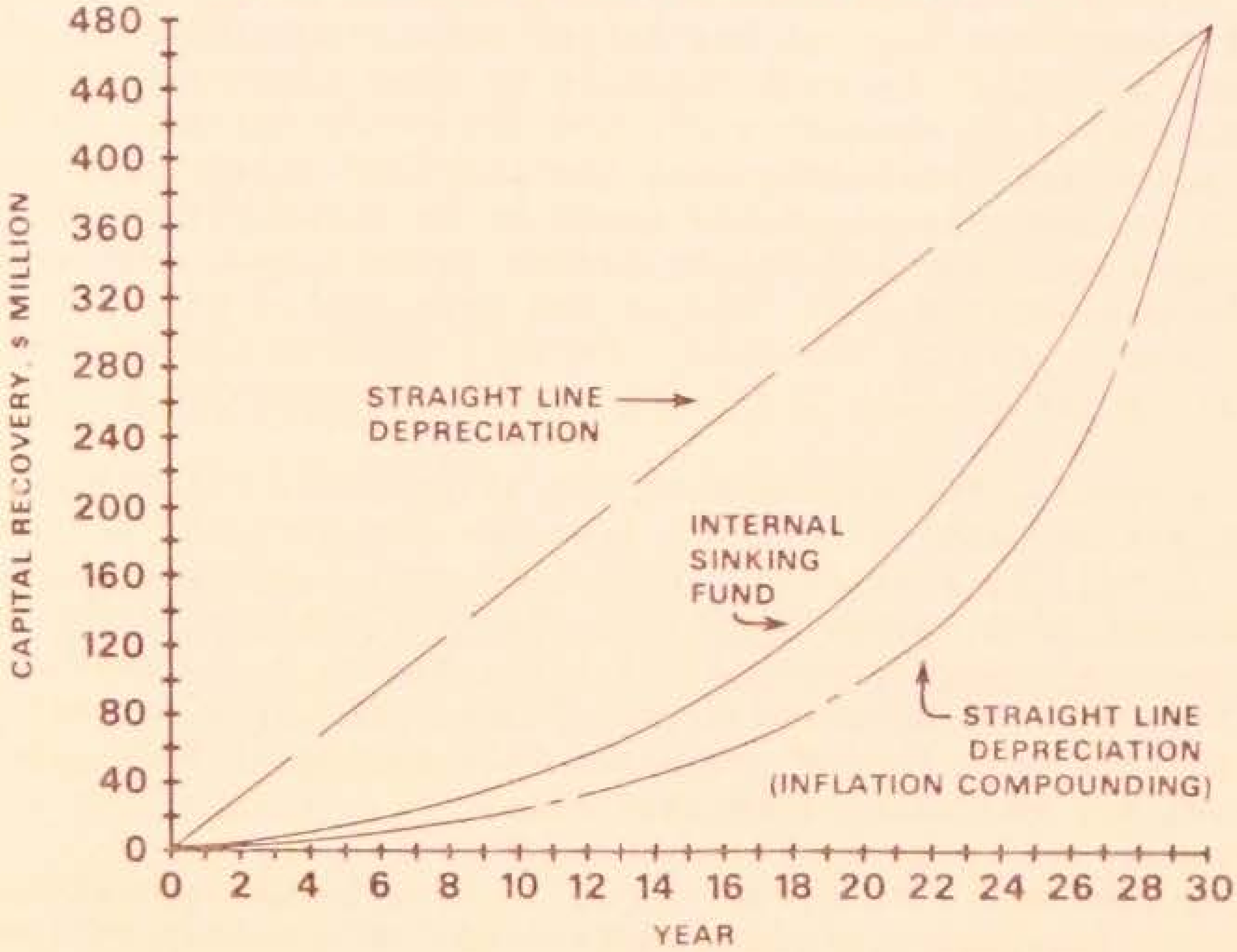


FIGURE 5

CUMULATIVE CAPITAL RECOVERY



NUCLEAR PLANT DECOMMISSIONING FINANCING

Preston A. Collins
Principal Consulting Engineer
Gilbert Associates, Inc.

The electric power industry has now been in the nuclear power generation business for approximately 25 years, having experienced its adolescent spurt of growth between 10 and 15 years ago. You may recall that in your personal experience, adolescence was a somewhat traumatic experience as you viewed it at the time of occurrence. In reviewing from where you are now, though, you might call them "the good old days". And so it is with nuclear power generation, except that the trauma for the nuclear power industry is continuing.

Not long after large commercial units became operational, the capital recovery aspects came under closer scrutiny. It became immediately apparent that positive net salvage was not to be expected and the longer and closer we looked at the problems of removing a nuclear plant, the more complex and costly it appeared. In addition to that, if that weren't enough, inflation began to increase at a phenomenal rate, crossing over that line that classifies it as double digit. There was a brief respite after the oil crisis of 1973, but it seems now that inflation was just getting its second wind. The problem of inflation now seems to have everyone's attention as indicated by the fact that the Securities Exchange Commission and then the Financial Accounting Standards Board have issued rules for reporting the effects of inflation in the financial statements.

In 1977 a group known as the Public Interest Research Group (PIRG) petitioned the Nuclear Regulatory Commission (NRC) to require nuclear plant operators to post bonds to be held in escrow to ensure that funds would be available for the decommissioning of each plant. The argument for these rules was that such an arrangement would ensure that decommissioning costs would be paid for by current beneficiaries of nuclear power and not by future generations. By such a statement, PIRG has implied that this is the only method by which such assurances can be obtained. Do they believe that financing a future cost is easier than financing new construction?

As a result, NRC issued a notice of proposed rulemaking on the subject requesting comments from the industry and interested parties. In July 1979, a draft of NUREG-0584 was issued and then revised November 1979, titled Assuring the Availability of Funds for Decommissioning Nuclear Facilities, by Mr. R. S. Wood of the Antitrust and Indemnity Group of NRC. The final report of that publication is due out sometime this spring (1980). In the draft form, Mr. Wood states on page 38:

> "The NRC's function should be to require assurance of the availability of decommissioning funds within reasonable bounds of cost effectiveness."

The question then is, how much will it cost to provide "financial assurance" as defined by NRC by any means other than through the normal net salvage accounting procedures as set forth in the "Uniform System of Accounts".

In this presentation, the possible financing alternatives will be presented under the assumptions of an ideal economic environment of no inflation and without the encumbrances of our not-always-clear tax laws. Then the scenario will be changed by adding our present tax laws and their options, then the effects of inflation will be added.

THE BASIC FINANCING ALTERNATIVES

Three methods of financing have been identified.

1. Funding at plant licensing. This would require the operator to establish a fund into which the operator would deposit an amount equal to the estimated cost of decommissioning at plant licensing. This amount would be raised through normal financing procedures, included in the rate base and amortized over the life of the plant. In this presentation it is assumed that the fund need contain only the amount required to cover the decommissioning cost; therefore, any interest earned would be returned to the operator to be treated as income and thereby reduce the revenue requirement. These earnings are assumed to be a part of the return on capital and the fund appears to have an earning rate equal to the rate of inflation.

2. Funding the decommissioning reserve. This also requires a fund, but would require that deposits be made by the operator from revenues in an amount equal to the accruals to recover the cost of decommissioning. Earnings on the fund would be treated in the same manner as that of funding at licensing except the amount in the fund need only be the sum of the accruals to date.

3. Finance at retirement. This is the same method currently used when negative net salvage is incurred. No fund is required. The estimated decommissioning cost is amortized over the plant life.

COMPARISON OF THE BASIC METHODS

Method 1.

Under the assumption of zero inflation and no income taxes, the funding at licensing, Method 1, creates rate base in an amount equal to the fund (the estimated decommissioning cost). The amortization expense is a constant. The amortization accruals are credited to the reserve for decommissioning thereby reducing rate base linearly which in turn reduces the revenue requirement linearly. Assuming a 4% cost of capital and 25-year plant life, the revenue requirement begins at 8% of the estimated decommissioning cost at age zero and decreases to 4% at age 25. If income tax on the return on capital is added at 50% tax rate, the revenue requirement begins at 12% and decreases to the same 4%. See Case #1, Figure 1.

Method 2.

The funded reserve method creates a constant revenue requirement of 4% since there is no rate base created at all. Each dollar of revenue is deposited in an external fund and offset with a credit of the same amount to the reserve. Due to the fact that there is no capital, the return on capital and related taxes are zero. See Case #2, Figure 1.

Method 3.

In the case of financing at retirement, rate base is zero at age zero but the accruals to the reserve create negative rate base decreasing linearly to a negative amount equal to the decommissioning cost. The negative rate base constitutes customer contributed capital and therefore produces a revenue requirement equal to 4% of the estimated decommissioning cost at age zero dropping to 0% at age 25. The addition of income taxes at the 50% rate produces a revenue requirement starting at the same 4% at age zero but decreasing to -4%. This may sound strange since taxes can't be negative (at least for corporations) but remember, this is superimposed on all other company operations since we are really looking at the net effect of decommissioning financing alternatives. In this specific instance, the negative rate base actually pays for the decommissioning. Depending on the relationship of the life to the cost of capital, the negative rate base may or may not finance the decommissioning.

The total revenue requirement for these three basic methods is represented in Figure 1 by the area under the particular curve with that area below the zero percent axis representing negative revenues. Of these alternatives it can easily be seen that only financing at retirement, Method 3, produces any potential for a total revenue requirement of zero or less. Regardless of how one plays with the numbers in terms of life and return on capital, it will always produce the smallest revenue requirement.

THE EFFECT OF INCOME TAX LAWS

Complicating the picture is the problem of income tax expense in the revenue requirement and accounting for it. The 1971 Revenue Act established the "Asset Depreciation Range" system of depreciation allowance calculations for computing deductions from taxable income. The main features of this system were accelerated depreciation and a range of acceptable lives within plus or minus 20% of the guideline life and the expensing of removal costs.

The purpose of this system was to stimulate the economy through tax savings by permitting a company to accelerate the depreciation of new plant investments. This was effective in the unregulated industries but in the regulated industries there have been efforts by regulatory agencies to pass these savings on to the customers directly. This rate making philosoply is called "flow-through". The rate making philosophy wherein only the normal straight-line depreciation is used for computing tax depreciation expense component of the revenue requirement is known as "normalization".

In accounting for removal costs a similar timing difference occurs except in the reverse direction. Under ADR rules removal costs may not be included as a component of the depreciation but are expensed when incurred. In flow-through accounting and rate making this produces an inequitable cost allocation to the accounting periods for a nuclear plant because the expensing of removal costs produces a negative revenue requirement during the decommissioning period. These reduced revenue requirements properly belong to the customers served by the plant while it is in service. Figure 2 illustrates the revenue requirements under flow-through.

In order to overcome this inequity many companies have decided to credit the accumulated provision for depreciation with the amount of the tax saving created by the tax computation of expensing removal costs. This also means that they should reduce the book depreciation accrual in proportion to the tax credit to be received. Many have called this procedure "normalization". It does have the effect of normalizing the revenue requirement but not in the same manner as another procedure which could also be called "normalization" which follows those procedures paralleling "deferred tax accounting", described as follows.

In the normalizing procedures that account for the difference between accelerated and straight-line depreciation, the difference between the taxes under accelerated and straight-line depreciation is credited to a "deferred tax" account. If the same principles are applied to the tax differences created by removal costs, then the taxes paid due to the amortization of the removal costs should be debited to the deferred-tax account.

In order to avoid confusion between these procedures, I will use the following terminology in referring to the removal cost aspects.

Net Income Accounting - the tax savings are credited to an income or expense account as they occur. This is pure "flow through" as shown in Figure 2 and referred to as Cases 1-A, 2-A, and 3-A. A five-year decommissioning period is assumed.

Depreciation Reserve Accounting - tax savings are credited to the accumulated provision for depreciation with an appropriate reduction to the depreciation accrual. These are illustrated in Figure 3 as Cases 1-B, 2-B, and 3-B.

Deferred Tax Accounting - taxes paid to cover the amortization of removal costs are debited to the deferred-tax account with the tax saving credited to the same account when removal costs are incurred. These are also illustrated in Figure 3 and referred to as Cases 1-C, 2-C and 3-C.

ACCOUNTING FOR INFLATION

Having now reviewed the basic financial alternatives under the ideal economic environment of zero inflation, let us turn our attention to what is currently happening to such procedures under an assumed constant rate of inflation. It would seem logical to assume that the revenue requirement of a case wherein inflation is present should be the same as for zero inflation provided the comparison is in the same units of purchasing power. Therefore, in the cases where a constant rate of inflation is assumed in calculating the various components of the revenue requirement, the total revenue requirement has been discounted back to age zero in order to establish an equivalent constant-dollar revenue requirement.

Two methods of projecting the inflated value of decommissioning into the future are:

1. Project the current estimated cost to the end of the coming year and compute the accrual on a remaining life basis.

2. Project the current estimated cost to the estimated date of retirement and compute the accrual on a remaining life basis.

The constant-dollar revenue requirement patterns for these methods applied to the previous cases are illustrated in Figure 3 by case numbers suffixed by a 1 or a 2 as defined above. It can readily be seen that none of these patterns are identical with that of its parent (zero inflation).

The additional assumptions applied in these cases were that the rate of inflation was 8% and the return on capital was 4% above the inflation rate, or 12%. However, the 12% rate of return really has two functions - first to pay a return on the capital comparable to that required under zero inflation and, second, to protect the capital from erosion by inflation. If this is true then 8% of the return should be retained and placed in the reserve for decommissioning and 4% used for payments for the return on capital.

The constant-dollar revenue requirements for these situations are illustrated in Figure 4 and are identified by using the suffixes 3 and 4 in the case number in place of 1 and 2, respectively, as defined above. The assumptions are that the reserve for decommissioning is compounded annually at the rate of inflation, 8%, and the return on capital is 4%. This does not mean to imply that a company's return on capital is only 4% in rate proceedings; 12% is to be used there. It is only a difference in the accounting for it. The 8% compounding is in the revenue requirement, also.

The data from which the revenue requirement graphs of Figures 3 and 4 were plotted are contained in computer printouts in the appendix.

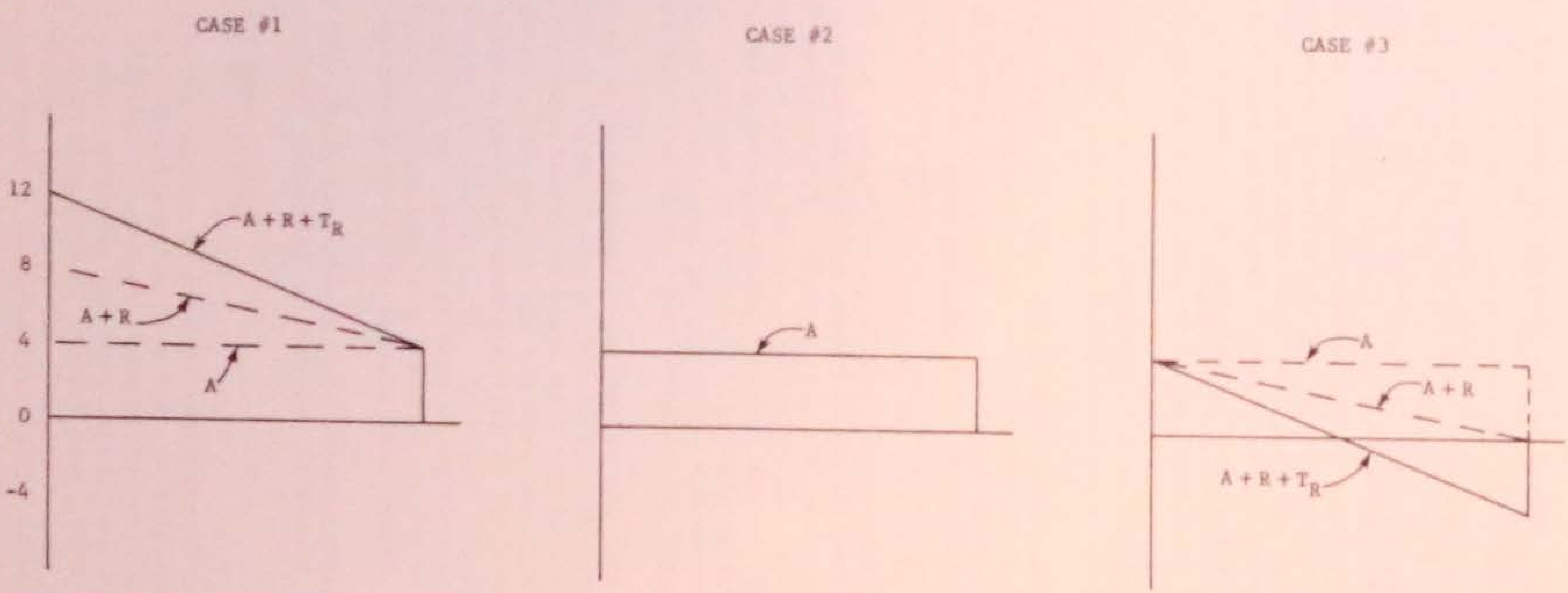
SUMMARY AND CONCLUSIONS

It has been the purpose of this presentation to review and hopefully clarify the accounting principles that go into analyzing the basic financing methods. It has not been my purpose to draw any hard and fast conclusion concerning the best method, nor has it been intended to be a position or policy of Gilbert Associates. Each situation should be decided based upon the parameters that are peculiar to it. The parameters used in the examples are not to be taken as the "right" numbers but were used only for instruction purposes. The "right" parameters will depend on the company or agency and its own particular financial position.

There is one principle, however, that should find universal application that should be emphasized. In the computer printouts in the appendix, there is a column labelled "Ratio" which is the reserve for decommissioning divided by the then current estimated cost of decommissioning. Regardless of the amount estimated to decommission a plant, the actual reserve divided by the estimated decommissioning cost at that particular age should be reasonably close to this ratio as computed using the appropriate life. This ratio should serve as a monitoring device to signal for corrections in the accruals.

REVENUE REQUIREMENT COMPONENTS

WITH TAXES ONLY ON RETURN ON CAPITAL



A = Amortization Expense

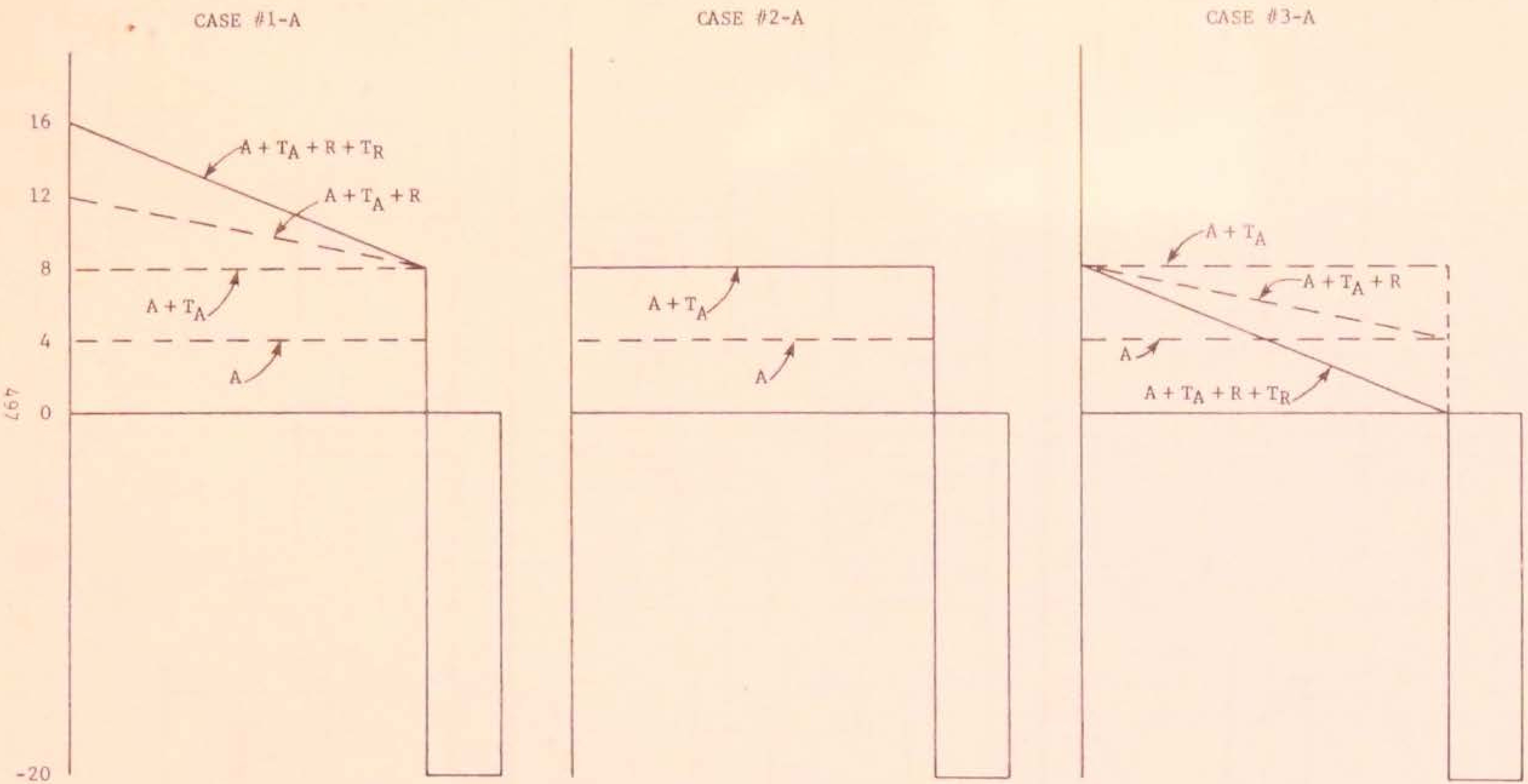
R = Return on Capital

T_R = Tax on Return on Capital

FIGURE 1

REVENUE REQUIREMENT COMPONENTS

UNDER PURE FLOW-THROUGH



A = Amortization Expense

T_A = Tax on Amortization Expense

R = Return on Capital

T_R = Tax on Return on Capital

FIGURE 2

COMPARISON OF REVENUE REQUIREMENTS

FIGURE 3

COMPARISON OF REVENUE REQUIREMENTS
(CONTINUED)

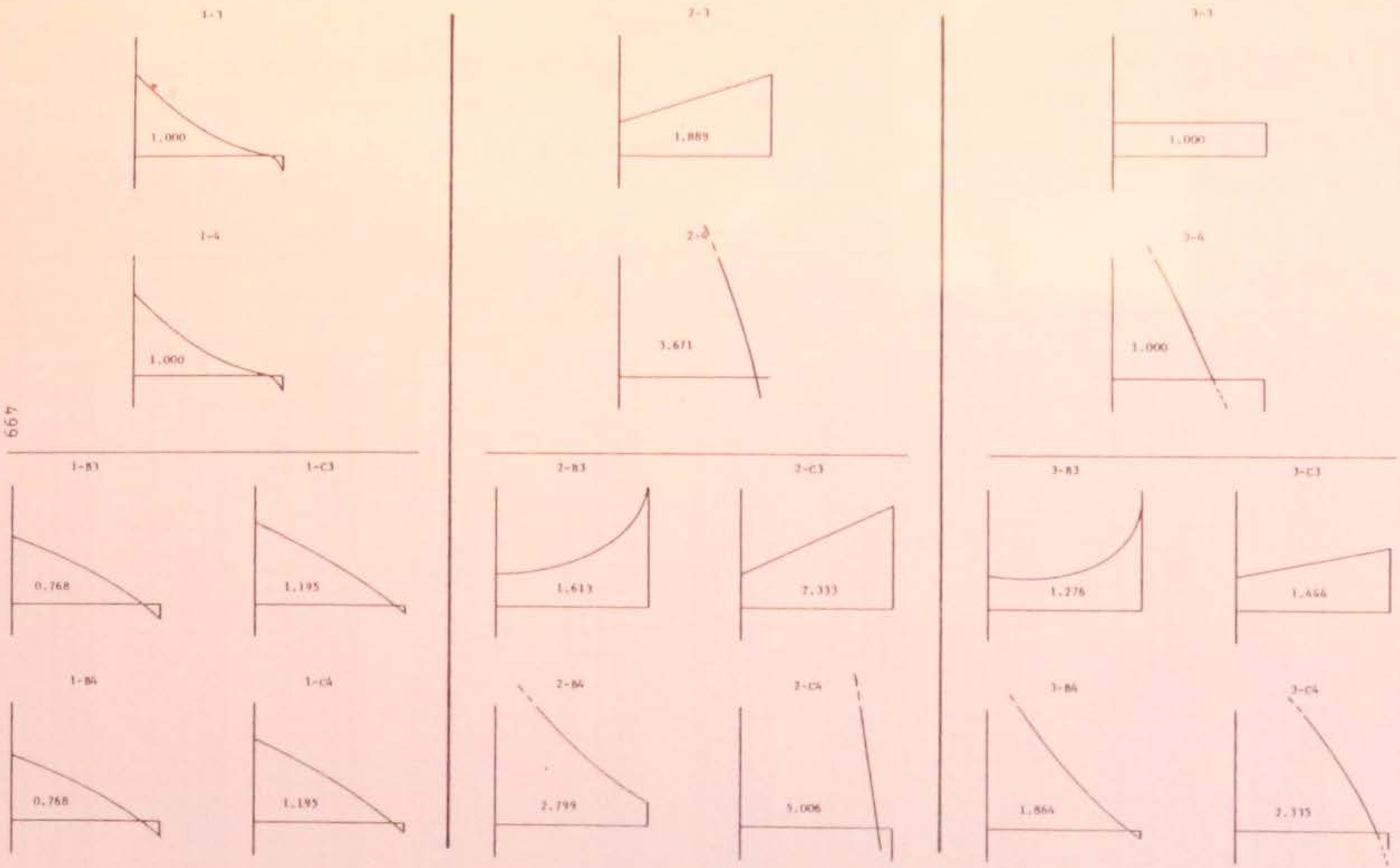


FIGURE 4

APPENDIX

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #1

FINANCING METHOD: ESTABLISH FUND AT AGE ZERO

TAX ACCOUNTING METHOD: NOT APPLICABLE

CAPITAL REQUIRED TO ESTABLISH FUND AT AGE ZERO
AMORTIZED OVER THE PLANT LIFE.
ASSUMED RATE OF INFLATION: 0.0 %

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 0.0 %
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	1.000	-1.000									
1	1.000	-0.960	-0.040	0.0	0.040	0.040	0.040	-0.120	-0.120	1.000	0.040
2	1.000	-0.920	-0.080	0.0	0.040	0.038	0.038	-0.117	-0.117	1.000	0.080
3	1.000	-0.880	-0.120	0.0	0.040	0.037	0.037	-0.114	-0.114	1.000	0.120
4	1.000	-0.840	-0.160	0.0	0.040	0.035	0.035	-0.110	-0.110	1.000	0.160
5	1.000	-0.800	-0.200	0.0	0.040	0.034	0.034	-0.107	-0.107	1.000	0.200
6	1.000	-0.760	-0.240	0.0	0.040	0.032	0.032	-0.104	-0.104	1.000	0.240
7	1.000	-0.720	-0.280	0.0	0.040	0.030	0.030	-0.101	-0.101	1.000	0.280
8	1.000	-0.680	-0.320	0.0	0.040	0.029	0.029	-0.098	-0.098	1.000	0.320
9	1.000	-0.640	-0.360	0.0	0.040	0.027	0.027	-0.094	-0.094	1.000	0.360
10	1.000	-0.600	-0.400	0.0	0.040	0.026	0.026	-0.091	-0.091	1.000	0.400
11	1.000	-0.560	-0.440	0.0	0.040	0.024	0.024	-0.088	-0.088	1.000	0.440
12	1.000	-0.520	-0.480	0.0	0.040	0.022	0.022	-0.085	-0.085	1.000	0.480
13	1.000	-0.480	-0.520	0.0	0.040	0.021	0.021	-0.082	-0.082	1.000	0.520
14	1.000	-0.440	-0.560	0.0	0.040	0.019	0.019	-0.078	-0.078	1.000	0.560
15	1.000	-0.400	-0.600	0.0	0.040	0.018	0.018	-0.075	-0.075	1.000	0.600
16	1.000	-0.360	-0.640	0.0	0.040	0.016	0.016	-0.072	-0.072	1.000	0.640
17	1.000	-0.320	-0.680	0.0	0.040	0.014	0.014	-0.069	-0.069	1.000	0.680
18	1.000	-0.280	-0.720	0.0	0.040	0.013	0.013	-0.066	-0.066	1.000	0.720
19	1.000	-0.240	-0.760	0.0	0.040	0.011	0.011	-0.062	-0.062	1.000	0.760
20	1.000	-0.200	-0.800	0.0	0.040	0.010	0.010	-0.059	-0.059	1.000	0.800
21	1.000	-0.160	-0.840	0.0	0.040	0.008	0.008	-0.056	-0.056	1.000	0.840
22	1.000	-0.120	-0.880	0.0	0.040	0.006	0.006	-0.053	-0.053	1.000	0.880
23	1.000	-0.080	-0.920	0.0	0.040	0.005	0.005	-0.050	-0.050	1.000	0.920
24	1.000	-0.040	-0.960	0.0	0.040	0.003	0.003	-0.046	-0.046	1.000	0.960
25	1.000	-0.000	-1.000	0.0	0.040	0.002	0.002	-0.043	-0.043	1.000	1.000
							TOTAL	-2.040	-2.040		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #2

FINANCING METHOD: PLACE ACCRUALS IN A FUND

TAX ACCOUNTING METHOD: NOT APPLICABLE

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 0.0 %

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 0.0 %
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.040	0.0	-0.040	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.040
2	0.080	0.0	-0.080	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.080
3	0.120	0.0	-0.120	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.120
4	0.160	0.0	-0.160	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.160
5	0.200	0.0	-0.200	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.200
6	0.240	0.0	-0.240	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.240
7	0.280	0.0	-0.280	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.280
8	0.320	0.0	-0.320	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.320
9	0.360	0.0	-0.360	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.360
10	0.400	0.0	-0.400	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.400
11	0.440	0.0	-0.440	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.440
12	0.480	0.0	-0.480	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.480
13	0.520	0.0	-0.520	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.520
14	0.560	0.0	-0.560	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.560
15	0.600	0.0	-0.600	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.600
16	0.640	0.0	-0.640	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.640
17	0.680	0.0	-0.680	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.680
18	0.720	0.0	-0.720	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.720
19	0.760	0.0	-0.760	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.760
20	0.800	0.0	-0.800	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.800
21	0.840	0.0	-0.840	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.840
22	0.880	0.0	-0.880	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.880
23	0.920	0.0	-0.920	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.920
24	0.960	0.0	-0.960	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.960
25	1.000	0.0	-1.000	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	1.000
							TOTAL	-1.000	-1.000		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #3

FINANCING METHOD: FINANCE AT DECOMMISSIONING

TAX ACCOUNTING METHOD: NOT APPLICABLE

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 0.0 %

RATE OF RETURN ON CAPITAL: 4.00%

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 0.0 %

RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.0	0.040	-0.040	0.0	0.040	0.0	0.0	-0.040	-0.040	1.000	0.040
2	0.0	0.080	-0.080	0.0	0.040	-0.002	-0.002	-0.037	-0.037	1.000	0.080
3	0.0	0.120	-0.120	0.0	0.040	-0.003	-0.003	-0.034	-0.034	1.000	0.120
4	0.0	0.160	-0.160	0.0	0.040	-0.005	-0.005	-0.030	-0.030	1.000	0.160
5	0.0	0.200	-0.200	0.0	0.040	-0.006	-0.006	-0.027	-0.027	1.000	0.200
6	0.0	0.240	-0.240	0.0	0.040	-0.008	-0.008	-0.024	-0.024	1.000	0.240
7	0.0	0.280	-0.280	0.0	0.040	-0.010	-0.010	-0.021	-0.021	1.000	0.280
8	0.0	0.320	-0.320	0.0	0.040	-0.011	-0.011	-0.018	-0.018	1.000	0.320
9	0.0	0.360	-0.360	0.0	0.040	-0.013	-0.013	-0.014	-0.014	1.000	0.360
10	0.0	0.400	-0.400	0.0	0.040	-0.014	-0.014	-0.011	-0.011	1.000	0.400
11	0.0	0.440	-0.440	0.0	0.040	-0.016	-0.016	-0.008	-0.008	1.000	0.440
12	0.0	0.480	-0.480	0.0	0.040	-0.018	-0.018	-0.005	-0.005	1.000	0.480
13	0.0	0.520	-0.520	0.0	0.040	-0.019	-0.019	-0.002	-0.002	1.000	0.520
14	0.0	0.560	-0.560	0.0	0.040	-0.021	-0.021	0.002	0.002	1.000	0.560
15	0.0	0.600	-0.600	0.0	0.040	-0.022	-0.022	0.005	0.005	1.000	0.600
16	0.0	0.640	-0.640	0.0	0.040	-0.024	-0.024	0.008	0.008	1.000	0.640
17	0.0	0.680	-0.680	0.0	0.040	-0.026	-0.026	0.011	0.011	1.000	0.680
18	0.0	0.720	-0.720	0.0	0.040	-0.027	-0.027	0.014	0.014	1.000	0.720
19	0.0	0.760	-0.760	0.0	0.040	-0.029	-0.029	0.018	0.018	1.000	0.760
20	0.0	0.800	-0.800	0.0	0.040	-0.030	-0.030	0.021	0.021	1.000	0.800
21	0.0	0.840	-0.840	0.0	0.040	-0.032	-0.032	0.024	0.024	1.000	0.840
22	0.0	0.880	-0.880	0.0	0.040	-0.034	-0.034	0.027	0.027	1.000	0.880
23	0.0	0.920	-0.920	0.0	0.040	-0.035	-0.035	0.030	0.030	1.000	0.920
24	0.0	0.960	-0.960	0.0	0.040	-0.037	-0.037	0.034	0.034	1.000	0.960
25	0.0	1.000	-1.000	0.0	0.040	-0.038	-0.038	0.037	0.037	1.000	1.000
							TOTAL	-0.040	-0.040		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #1-B

FINANCING METHOD: ESTABLISH FUND AT AGE ZERO

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

CAPITAL REQUIRED TO ESTABLISH FUND AT AGE ZERO
AMORTIZED OVER THE PLANT LIFE.
ASSUMED RATE OF INFLATION: 0.0 %

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %
TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.500	-0.500									
1	0.500	-0.480	-0.020	0.0	0.020	0.040	0.020	-0.080	-0.080	1.000	0.020
2	0.500	-0.460	-0.040	0.0	0.020	0.039	0.019	-0.078	-0.078	1.000	0.040
3	0.500	-0.440	-0.060	0.0	0.020	0.038	0.018	-0.077	-0.077	1.000	0.060
4	0.500	-0.420	-0.080	0.0	0.020	0.038	0.018	-0.075	-0.075	1.000	0.080
5	0.500	-0.400	-0.100	0.0	0.020	0.037	0.017	-0.074	-0.074	1.000	0.100
6	0.500	-0.380	-0.120	0.0	0.020	0.036	0.016	-0.072	-0.072	1.000	0.120
7	0.500	-0.360	-0.140	0.0	0.020	0.035	0.015	-0.070	-0.070	1.000	0.140
8	0.500	-0.340	-0.160	0.0	0.020	0.034	0.014	-0.069	-0.069	1.000	0.160
9	0.500	-0.320	-0.180	0.0	0.020	0.034	0.014	-0.067	-0.067	1.000	0.180
10	0.500	-0.300	-0.200	0.0	0.020	0.033	0.013	-0.066	-0.066	1.000	0.200
11	0.500	-0.280	-0.220	0.0	0.020	0.032	0.012	-0.064	-0.064	1.000	0.220
12	0.500	-0.260	-0.240	0.0	0.020	0.031	0.011	-0.062	-0.062	1.000	0.240
13	0.500	-0.240	-0.260	0.0	0.020	0.030	0.010	-0.061	-0.061	1.000	0.260
14	0.500	-0.220	-0.280	0.0	0.020	0.030	0.010	-0.059	-0.059	1.000	0.280
15	0.500	-0.200	-0.300	0.0	0.020	0.029	0.009	-0.058	-0.058	1.000	0.300
16	0.500	-0.180	-0.320	0.0	0.020	0.028	0.008	-0.056	-0.056	1.000	0.320
17	0.500	-0.160	-0.340	0.0	0.020	0.027	0.007	-0.054	-0.054	1.000	0.340
18	0.500	-0.140	-0.360	0.0	0.020	0.026	0.006	-0.053	-0.053	1.000	0.360
19	0.500	-0.120	-0.380	0.0	0.020	0.026	0.006	-0.051	-0.051	1.000	0.380
20	0.500	-0.100	-0.400	0.0	0.020	0.025	0.005	-0.050	-0.050	1.000	0.400
21	0.500	-0.080	-0.420	0.0	0.020	0.024	0.004	-0.048	-0.048	1.000	0.420
22	0.500	-0.060	-0.440	0.0	0.020	0.023	0.003	-0.046	-0.046	1.000	0.440
23	0.500	-0.040	-0.460	0.0	0.020	0.022	0.002	-0.045	-0.045	1.000	0.460
24	0.500	-0.020	-0.480	0.0	0.020	0.022	0.002	-0.043	-0.043	1.000	0.480
25	0.500	0.0	-0.500	0.0	0.020	0.021	0.001	-0.042	-0.042	1.000	0.500
							TOTAL	-1.520	-1.520		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #1-C

FINANCING METHOD: ESTABLISH FUND AT AGE ZERO

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

CAPITAL REQUIRED TO ESTABLISH FUND AT AGE ZERO
AMORTIZED OVER THE PLANT LIFE.
ASSUMED RATE OF INFLATION: 0.0 %

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	1.000	-1.000									
1	1.000	-0.980	-0.040	0.020	0.040	0.040	0.040	-0.120	-0.120	1.000	0.040
2	1.000	-0.960	-0.080	0.040	0.040	0.039	0.039	-0.118	-0.118	1.000	0.080
3	1.000	-0.940	-0.120	0.060	0.040	0.038	0.038	-0.117	-0.117	1.000	0.120
4	1.000	-0.920	-0.160	0.080	0.040	0.038	0.038	-0.115	-0.115	1.000	0.160
5	1.000	-0.900	-0.200	0.100	0.040	0.037	0.037	-0.114	-0.114	1.000	0.200
6	1.000	-0.880	-0.240	0.120	0.040	0.036	0.036	-0.112	-0.112	1.000	0.240
7	1.000	-0.860	-0.280	0.140	0.040	0.035	0.035	-0.110	-0.110	1.000	0.280
8	1.000	-0.840	-0.320	0.160	0.040	0.034	0.034	-0.109	-0.109	1.000	0.320
9	1.000	-0.820	-0.360	0.180	0.040	0.034	0.034	-0.107	-0.107	1.000	0.360
10	1.000	-0.800	-0.400	0.200	0.040	0.033	0.033	-0.106	-0.106	1.000	0.400
11	1.000	-0.780	-0.440	0.220	0.040	0.032	0.032	-0.104	-0.104	1.000	0.440
12	1.000	-0.760	-0.480	0.240	0.040	0.031	0.031	-0.102	-0.102	1.000	0.480
13	1.000	-0.740	-0.520	0.260	0.040	0.030	0.030	-0.101	-0.101	1.000	0.520
14	1.000	-0.720	-0.560	0.280	0.040	0.030	0.030	-0.099	-0.099	1.000	0.560
15	1.000	-0.700	-0.600	0.300	0.040	0.029	0.029	-0.098	-0.098	1.000	0.600
16	1.000	-0.680	-0.640	0.320	0.040	0.028	0.028	-0.096	-0.096	1.000	0.640
17	1.000	-0.660	-0.680	0.340	0.040	0.027	0.027	-0.094	-0.094	1.000	0.680
18	1.000	-0.640	-0.720	0.360	0.040	0.026	0.026	-0.093	-0.093	1.000	0.720
19	1.000	-0.620	-0.760	0.380	0.040	0.026	0.026	-0.091	-0.091	1.000	0.760
20	1.000	-0.600	-0.800	0.400	0.040	0.025	0.025	-0.090	-0.090	1.000	0.800
21	1.000	-0.580	-0.840	0.420	0.040	0.024	0.024	-0.088	-0.088	1.000	0.840
22	1.000	-0.560	-0.880	0.440	0.040	0.023	0.023	-0.086	-0.086	1.000	0.880
23	1.000	-0.540	-0.920	0.460	0.040	0.022	0.022	-0.085	-0.085	1.000	0.920
24	1.000	-0.520	-0.960	0.480	0.040	0.022	0.022	-0.083	-0.083	1.000	0.960
25	1.000	-0.500	-1.000	0.500	0.040	0.021	0.021	-0.082	-0.082	1.000	1.000
							TOTAL	-2.520	-2.520		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #2-B

FINANCING METHOD: PLACE ACCRUALS IN A FUND

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 0.0 %

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %
TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.020	0.0	-0.020	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.020
2	0.040	0.0	-0.040	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.040
3	0.060	0.0	-0.060	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.060
4	0.080	0.0	-0.080	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.080
5	0.100	0.0	-0.100	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.100
6	0.120	0.0	-0.120	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.120
7	0.140	0.0	-0.140	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.140
8	0.160	0.0	-0.160	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.160
9	0.180	0.0	-0.180	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.180
10	0.200	0.0	-0.200	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.200
11	0.220	0.0	-0.220	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.220
12	0.240	0.0	-0.240	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.240
13	0.260	0.0	-0.260	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.260
14	0.280	0.0	-0.280	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.280
15	0.300	0.0	-0.300	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.300
16	0.320	0.0	-0.320	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.320
17	0.340	0.0	-0.340	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.340
18	0.360	0.0	-0.360	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.360
19	0.380	0.0	-0.380	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.380
20	0.400	0.0	-0.400	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.400
21	0.420	0.0	-0.420	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.420
22	0.440	0.0	-0.440	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.440
23	0.460	0.0	-0.460	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.460
24	0.480	0.0	-0.480	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.480
25	0.500	0.0	-0.500	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.500
							TOTAL	-1.000	-1.000		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #2-C

FINANCING METHOD: PLACE ACCRUALS IN A FUND

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 0.0 %

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.040	-0.020	-0.040	0.020	0.040	0.0	0.0	-0.040	-0.040	1.000	0.040
2	0.080	-0.040	-0.080	0.040	0.040	0.001	0.001	-0.042	-0.042	1.000	0.080
3	0.120	-0.060	-0.120	0.060	0.040	0.002	0.002	-0.043	-0.043	1.000	0.120
4	0.160	-0.080	-0.160	0.080	0.040	0.002	0.002	-0.045	-0.045	1.000	0.160
5	0.200	-0.100	-0.200	0.100	0.040	0.003	0.003	-0.046	-0.046	1.000	0.200
6	0.240	-0.120	-0.240	0.120	0.040	0.004	0.004	-0.048	-0.048	1.000	0.240
7	0.280	-0.140	-0.280	0.140	0.040	0.005	0.005	-0.050	-0.050	1.000	0.280
8	0.320	-0.160	-0.320	0.160	0.040	0.006	0.006	-0.051	-0.051	1.000	0.320
9	0.360	-0.180	-0.360	0.180	0.040	0.006	0.006	-0.053	-0.053	1.000	0.360
10	0.400	-0.200	-0.400	0.200	0.040	0.007	0.007	-0.054	-0.054	1.000	0.400
11	0.440	-0.220	-0.440	0.220	0.040	0.008	0.008	-0.056	-0.056	1.000	0.440
12	0.480	-0.240	-0.480	0.240	0.040	0.009	0.009	-0.058	-0.058	1.000	0.480
13	0.520	-0.260	-0.520	0.260	0.040	0.010	0.010	-0.059	-0.059	1.000	0.520
14	0.560	-0.280	-0.560	0.280	0.040	0.010	0.010	-0.061	-0.061	1.000	0.560
15	0.600	-0.300	-0.600	0.300	0.040	0.011	0.011	-0.062	-0.062	1.000	0.600
16	0.640	-0.320	-0.640	0.320	0.040	0.012	0.012	-0.064	-0.064	1.000	0.640
17	0.680	-0.340	-0.680	0.340	0.040	0.013	0.013	-0.066	-0.066	1.000	0.680
18	0.720	-0.360	-0.720	0.360	0.040	0.014	0.014	-0.067	-0.067	1.000	0.720
19	0.760	-0.380	-0.760	0.380	0.040	0.014	0.014	-0.069	-0.069	1.000	0.760
20	0.800	-0.400	-0.800	0.400	0.040	0.015	0.015	-0.070	-0.070	1.000	0.800
21	0.840	-0.420	-0.840	0.420	0.040	0.016	0.016	-0.072	-0.072	1.000	0.840
22	0.880	-0.440	-0.880	0.440	0.040	0.017	0.017	-0.074	-0.074	1.000	0.880
23	0.920	-0.460	-0.920	0.460	0.040	0.018	0.018	-0.075	-0.075	1.000	0.920
24	0.960	-0.480	-0.960	0.480	0.040	0.018	0.018	-0.077	-0.077	1.000	0.960
25	1.000	-0.500	-1.000	0.500	0.040	0.019	0.019	-0.078	-0.078	1.000	1.000
							TOTAL	-1.480	-1.480		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #3-B

FINANCING METHOD: FINANCE AT DECOMMISSIONING

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 0.0 %

RATE OF RETURN ON CAPITAL: 4.00%

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%

RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.0	0.020	-0.020	0.0	0.020	0.020	0.0	-0.040	-0.040	1.000	0.020
2	0.0	0.040	-0.040	0.0	0.020	0.019	-0.001	-0.038	-0.038	1.000	0.040
3	0.0	0.060	-0.060	0.0	0.020	0.018	-0.002	-0.037	-0.037	1.000	0.060
4	0.0	0.080	-0.080	0.0	0.020	0.018	-0.002	-0.035	-0.035	1.000	0.080
5	0.0	0.100	-0.100	0.0	0.020	0.017	-0.003	-0.034	-0.034	1.000	0.100
6	0.0	0.120	-0.120	0.0	0.020	0.016	-0.004	-0.032	-0.032	1.000	0.120
7	0.0	0.140	-0.140	0.0	0.020	0.015	-0.005	-0.030	-0.030	1.000	0.140
8	0.0	0.160	-0.160	0.0	0.020	0.014	-0.006	-0.029	-0.029	1.000	0.160
9	0.0	0.180	-0.180	0.0	0.020	0.014	-0.006	-0.027	-0.027	1.000	0.180
10	0.0	0.200	-0.200	0.0	0.020	0.013	-0.007	-0.026	-0.026	1.000	0.200
11	0.0	0.220	-0.220	0.0	0.020	0.012	-0.008	-0.024	-0.024	1.000	0.220
12	0.0	0.240	-0.240	0.0	0.020	0.011	-0.009	-0.022	-0.022	1.000	0.240
13	0.0	0.260	-0.260	0.0	0.020	0.010	-0.010	-0.021	-0.021	1.000	0.260
14	0.0	0.280	-0.280	0.0	0.020	0.010	-0.010	-0.019	-0.019	1.000	0.280
15	0.0	0.300	-0.300	0.0	0.020	0.009	-0.011	-0.018	-0.018	1.000	0.300
16	0.0	0.320	-0.320	0.0	0.020	0.008	-0.012	-0.016	-0.016	1.000	0.320
17	0.0	0.340	-0.340	0.0	0.020	0.007	-0.013	-0.014	-0.014	1.000	0.340
18	0.0	0.360	-0.360	0.0	0.020	0.006	-0.014	-0.013	-0.013	1.000	0.360
19	0.0	0.380	-0.380	0.0	0.020	0.006	-0.014	-0.011	-0.011	1.000	0.380
20	0.0	0.400	-0.400	0.0	0.020	0.005	-0.015	-0.010	-0.010	1.000	0.400
21	0.0	0.420	-0.420	0.0	0.020	0.004	-0.016	-0.008	-0.008	1.000	0.420
22	0.0	0.440	-0.440	0.0	0.020	0.003	-0.017	-0.006	-0.006	1.000	0.440
23	0.0	0.460	-0.460	0.0	0.020	0.002	-0.018	-0.005	-0.005	1.000	0.460
24	0.0	0.480	-0.480	0.0	0.020	0.002	-0.018	-0.003	-0.003	1.000	0.480
25	0.0	0.500	-0.500	0.0	0.020	0.001	-0.019	-0.002	-0.002	1.000	0.500
							TOTAL	-0.520	-0.520		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #3-C

FINANCING METHOD: FINANCE AT DECOMMISSIONING

RATE OF RETURN ON CAPITAL: 4.00%

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 0.0 %

RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.0	0.020	-0.040	0.020	0.040	0.0	0.0	-0.040	-0.040	1.000	0.040
2	0.0	0.040	-0.080	0.040	0.040	-0.001	-0.001	-0.038	-0.038	1.000	0.080
3	0.0	0.060	-0.120	0.060	0.040	-0.002	-0.002	-0.037	-0.037	1.000	0.120
4	0.0	0.080	-0.160	0.080	0.040	-0.002	-0.002	-0.035	-0.035	1.000	0.160
5	0.0	0.100	-0.200	0.100	0.040	-0.003	-0.003	-0.034	-0.034	1.000	0.200
6	0.0	0.120	-0.240	0.120	0.040	-0.004	-0.004	-0.032	-0.032	1.000	0.240
7	0.0	0.140	-0.280	0.140	0.040	-0.005	-0.005	-0.030	-0.030	1.000	0.280
8	0.0	0.160	-0.320	0.160	0.040	-0.006	-0.006	-0.029	-0.029	1.000	0.320
9	0.0	0.180	-0.360	0.180	0.040	-0.006	-0.006	-0.027	-0.027	1.000	0.360
10	0.0	0.200	-0.400	0.200	0.040	-0.007	-0.007	-0.026	-0.026	1.000	0.400
11	0.0	0.220	-0.440	0.220	0.040	-0.008	-0.008	-0.024	-0.024	1.000	0.440
12	0.0	0.240	-0.480	0.240	0.040	-0.009	-0.009	-0.022	-0.022	1.000	0.480
13	0.0	0.260	-0.520	0.260	0.040	-0.010	-0.010	-0.021	-0.021	1.000	0.520
14	0.0	0.280	-0.560	0.280	0.040	-0.010	-0.010	-0.019	-0.019	1.000	0.560
15	0.0	0.300	-0.600	0.300	0.040	-0.011	-0.011	-0.018	-0.018	1.000	0.600
16	0.0	0.320	-0.640	0.320	0.040	-0.012	-0.012	-0.016	-0.016	1.000	0.640
17	0.0	0.340	-0.680	0.340	0.040	-0.013	-0.013	-0.014	-0.014	1.000	0.680
18	0.0	0.360	-0.720	0.360	0.040	-0.014	-0.014	-0.013	-0.013	1.000	0.720
19	0.0	0.380	-0.760	0.380	0.040	-0.014	-0.014	-0.011	-0.011	1.000	0.760
20	0.0	0.400	-0.800	0.400	0.040	-0.015	-0.015	-0.010	-0.010	1.000	0.800
21	0.0	0.420	-0.840	0.420	0.040	-0.016	-0.016	-0.008	-0.008	1.000	0.840
22	0.0	0.440	-0.880	0.440	0.040	-0.017	-0.017	-0.006	-0.006	1.000	0.880
23	0.0	0.460	-0.920	0.460	0.040	-0.018	-0.018	-0.005	-0.005	1.000	0.920
24	0.0	0.480	-0.960	0.480	0.040	-0.018	-0.018	-0.003	-0.003	1.000	0.960
25	0.0	0.500	-1.000	0.500	0.040	-0.019	-0.019	-0.002	-0.002	1.000	1.000
							TOTAL	-0.520	-0.520		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #1-B1

FINANCING METHOD: ESTABLISH FUND AT AGE ZERO

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

CAPITAL REQUIRED TO ESTABLISH FUND AT AGE ZERO
AMORTIZED OVER THE PLANT LIFE.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 12.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.500	-0.500									
1	0.500	-0.480	-0.020	0.0	0.020	0.080	0.060	-0.160	-0.148	1.080	0.019
2	0.500	-0.460	-0.040	0.0	0.020	0.078	0.058	-0.155	-0.133	1.166	0.034
3	0.500	-0.440	-0.060	0.0	0.020	0.075	0.055	-0.150	-0.119	1.260	0.048
4	0.500	-0.420	-0.080	0.0	0.020	0.073	0.053	-0.146	-0.107	1.360	0.059
5	0.500	-0.400	-0.100	0.0	0.020	0.070	0.050	-0.141	-0.096	1.469	0.068
6	0.500	-0.380	-0.120	0.0	0.020	0.068	0.048	-0.136	-0.086	1.587	0.076
7	0.500	-0.360	-0.140	0.0	0.020	0.066	0.046	-0.131	-0.077	1.714	0.082
8	0.500	-0.340	-0.160	0.0	0.020	0.063	0.043	-0.126	-0.068	1.851	0.086
9	0.500	-0.320	-0.180	0.0	0.020	0.061	0.041	-0.122	-0.061	1.999	0.090
10	0.500	-0.300	-0.200	0.0	0.020	0.058	0.038	-0.117	-0.054	2.159	0.093
11	0.500	-0.280	-0.220	0.0	0.020	0.056	0.036	-0.112	-0.048	2.332	0.094
12	0.500	-0.260	-0.240	0.0	0.020	0.054	0.034	-0.107	-0.043	2.518	0.095
13	0.500	-0.240	-0.260	0.0	0.020	0.051	0.031	-0.102	-0.038	2.720	0.096
14	0.500	-0.220	-0.280	0.0	0.020	0.049	0.029	-0.098	-0.033	2.937	0.095
15	0.500	-0.200	-0.300	0.0	0.020	0.046	0.026	-0.093	-0.029	3.172	0.095
16	0.500	-0.180	-0.320	0.0	0.020	0.044	0.024	-0.088	-0.026	3.426	0.093
17	0.500	-0.160	-0.340	0.0	0.020	0.042	0.022	-0.083	-0.022	3.700	0.092
18	0.500	-0.140	-0.360	0.0	0.020	0.039	0.019	-0.078	-0.020	3.996	0.090
19	0.500	-0.120	-0.380	0.0	0.020	0.037	0.017	-0.074	-0.017	4.316	0.088
20	0.500	-0.100	-0.400	0.0	0.020	0.034	0.014	-0.069	-0.015	4.661	0.086
21	0.500	-0.080	-0.420	0.0	0.020	0.032	0.012	-0.064	-0.013	5.034	0.083
22	0.500	-0.060	-0.440	0.0	0.020	0.030	0.010	-0.059	-0.011	5.437	0.081
23	0.500	-0.040	-0.460	0.0	0.020	0.027	0.007	-0.054	-0.009	5.871	0.078
24	0.500	-0.020	-0.480	0.0	0.020	0.025	0.005	-0.050	-0.008	6.341	0.076
25	0.500	-0.000	-0.500	0.0	0.020	0.022	0.002	-0.045	-0.007	6.848	0.073
							TOTAL	-2.560	-1.287		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #1-B2

FINANCING METHOD: ESTABLISH FUND AT AGE ZERO

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

CAPITAL REQUIRED TO ESTABLISH FUND AT AGE ZERO
AMORTIZED OVER THE PLANT LIFE.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 12.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.500	-0.500									
1	0.500	-0.480	-0.020	0.0	0.020	0.080	0.060	-0.160	-0.148	1.080	0.019
2	0.500	-0.460	-0.040	0.0	0.020	0.078	0.058	-0.155	-0.133	1.166	0.034
3	0.500	-0.440	-0.060	0.0	0.020	0.075	0.055	-0.150	-0.119	1.260	0.048
4	0.500	-0.420	-0.080	0.0	0.020	0.073	0.053	-0.146	-0.107	1.360	0.059
5	0.500	-0.400	-0.100	0.0	0.020	0.070	0.050	-0.141	-0.096	1.469	0.068
6	0.500	-0.380	-0.120	0.0	0.020	0.068	0.048	-0.136	-0.086	1.587	0.076
7	0.500	-0.360	-0.140	0.0	0.020	0.066	0.046	-0.131	-0.077	1.714	0.082
8	0.500	-0.340	-0.160	0.0	0.020	0.063	0.043	-0.126	-0.068	1.851	0.086
9	0.500	-0.320	-0.180	0.0	0.020	0.061	0.041	-0.122	-0.061	1.999	0.090
10	0.500	-0.300	-0.200	0.0	0.020	0.058	0.038	-0.117	-0.054	2.159	0.093
11	0.500	-0.280	-0.220	0.0	0.020	0.056	0.036	-0.112	-0.048	2.332	0.094
12	0.500	-0.260	-0.240	0.0	0.020	0.054	0.034	-0.107	-0.043	2.518	0.095
13	0.500	-0.240	-0.260	0.0	0.020	0.051	0.031	-0.102	-0.038	2.720	0.096
14	0.500	-0.220	-0.280	0.0	0.020	0.049	0.029	-0.098	-0.033	2.937	0.095
15	0.500	-0.200	-0.300	0.0	0.020	0.046	0.026	-0.093	-0.029	3.172	0.095
16	0.500	-0.180	-0.320	0.0	0.020	0.044	0.024	-0.088	-0.026	3.426	0.093
17	0.500	-0.160	-0.340	0.0	0.020	0.042	0.022	-0.083	-0.022	3.700	0.092
18	0.500	-0.140	-0.360	0.0	0.020	0.039	0.019	-0.078	-0.020	3.996	0.090
19	0.500	-0.120	-0.380	0.0	0.020	0.037	0.017	-0.074	-0.017	4.316	0.088
20	0.500	-0.100	-0.400	0.0	0.020	0.034	0.014	-0.069	-0.015	4.661	0.086
21	0.500	-0.080	-0.420	0.0	0.020	0.032	0.012	-0.064	-0.013	5.034	0.083
22	0.500	-0.060	-0.440	0.0	0.020	0.030	0.010	-0.059	-0.011	5.437	0.081
23	0.500	-0.040	-0.460	0.0	0.020	0.027	0.007	-0.054	-0.009	5.871	0.078
24	0.500	-0.020	-0.480	0.0	0.020	0.025	0.005	-0.050	-0.008	6.341	0.076
25	0.500	-0.000	-0.500	0.0	0.020	0.022	0.002	-0.045	-0.007	6.848	0.073
							TOTAL	-2.560	-1.287		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #1-C1

FINANCING METHOD: ESTABLISH FUND AT AGE ZERO

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

CAPITAL REQUIRED TO ESTABLISH FUND AT AGE ZERO
AMORTIZED OVER THE PLANT LIFE.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 12.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	1.000	-1.000									
1	1.000	-0.980	-0.040	0.020	0.040	0.120	0.120	-0.280	-0.259	1.080	0.037
2	1.000	-0.960	-0.080	0.040	0.040	0.118	0.118	-0.275	-0.236	1.166	0.069
3	1.000	-0.940	-0.120	0.060	0.040	0.115	0.115	-0.270	-0.215	1.260	0.095
4	1.000	-0.920	-0.160	0.080	0.040	0.113	0.113	-0.266	-0.195	1.360	0.118
5	1.000	-0.900	-0.200	0.100	0.040	0.110	0.110	-0.261	-0.177	1.469	0.136
6	1.000	-0.880	-0.240	0.120	0.040	0.108	0.108	-0.256	-0.161	1.587	0.151
7	1.000	-0.860	-0.280	0.140	0.040	0.106	0.106	-0.251	-0.147	1.714	0.163
8	1.000	-0.840	-0.320	0.160	0.040	0.103	0.103	-0.246	-0.133	1.851	0.173
9	1.000	-0.820	-0.360	0.180	0.040	0.101	0.101	-0.242	-0.121	1.999	0.180
10	1.000	-0.800	-0.400	0.200	0.040	0.098	0.098	-0.237	-0.110	2.159	0.185
11	1.000	-0.780	-0.440	0.220	0.040	0.096	0.096	-0.232	-0.100	2.332	0.189
12	1.000	-0.760	-0.480	0.240	0.040	0.094	0.094	-0.227	-0.090	2.518	0.191
13	1.000	-0.740	-0.520	0.260	0.040	0.091	0.091	-0.222	-0.082	2.720	0.191
14	1.000	-0.720	-0.560	0.280	0.040	0.089	0.089	-0.218	-0.074	2.937	0.191
15	1.000	-0.700	-0.600	0.300	0.040	0.086	0.086	-0.213	-0.067	3.172	0.189
16	1.000	-0.680	-0.640	0.320	0.040	0.084	0.084	-0.208	-0.061	3.426	0.187
17	1.000	-0.660	-0.680	0.340	0.040	0.082	0.082	-0.203	-0.055	3.700	0.184
18	1.000	-0.640	-0.720	0.360	0.040	0.079	0.079	-0.198	-0.050	3.996	0.180
19	1.000	-0.620	-0.760	0.380	0.040	0.077	0.077	-0.194	-0.045	4.316	0.176
20	1.000	-0.600	-0.800	0.400	0.040	0.074	0.074	-0.189	-0.041	4.661	0.172
21	1.000	-0.580	-0.840	0.420	0.040	0.072	0.072	-0.184	-0.037	5.034	0.167
22	1.000	-0.560	-0.880	0.440	0.040	0.070	0.070	-0.179	-0.033	5.437	0.162
23	1.000	-0.540	-0.920	0.460	0.040	0.067	0.067	-0.174	-0.030	5.871	0.157
24	1.000	-0.520	-0.960	0.480	0.040	0.065	0.065	-0.170	-0.027	6.341	0.151
25	1.000	-0.500	-1.000	0.500	0.040	0.062	0.062	-0.165	-0.024	6.848	0.146
							TOTAL	-5.560	-2.567		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #1-C2

FINANCING METHOD: ESTABLISH FUND AT AGE ZERO

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

CAPITAL REQUIRED TO ESTABLISH FUND AT AGE ZERO
AMORTIZED OVER THE PLANT LIFE.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 12.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	1.000	-1.000									
1	1.000	-0.980	-0.040	0.020	0.040	0.120	0.120	-0.280	-0.259	1.080	0.037
2	1.000	-0.960	-0.080	0.040	0.040	0.118	0.118	-0.275	-0.236	1.166	0.069
3	1.000	-0.940	-0.120	0.060	0.040	0.115	0.115	-0.270	-0.215	1.260	0.095
4	1.000	-0.920	-0.160	0.080	0.040	0.113	0.113	-0.266	-0.195	1.360	0.118
5	1.000	-0.900	-0.200	0.100	0.040	0.110	0.110	-0.261	-0.177	1.469	0.136
6	1.000	-0.880	-0.240	0.120	0.040	0.108	0.108	-0.256	-0.161	1.587	0.151
7	1.000	-0.860	-0.280	0.140	0.040	0.106	0.106	-0.251	-0.147	1.714	0.163
8	1.000	-0.840	-0.320	0.160	0.040	0.103	0.103	-0.246	-0.133	1.851	0.173
9	1.000	-0.820	-0.360	0.180	0.040	0.101	0.101	-0.242	-0.121	1.999	0.180
10	1.000	-0.800	-0.400	0.200	0.040	0.098	0.098	-0.237	-0.110	2.159	0.185
11	1.000	-0.780	-0.440	0.220	0.040	0.096	0.096	-0.232	-0.100	2.332	0.189
12	1.000	-0.760	-0.480	0.240	0.040	0.094	0.094	-0.227	-0.090	2.518	0.191
13	1.000	-0.740	-0.520	0.260	0.040	0.091	0.091	-0.222	-0.082	2.720	0.191
14	1.000	-0.720	-0.560	0.280	0.040	0.089	0.089	-0.218	-0.074	2.937	0.191
15	1.000	-0.700	-0.600	0.300	0.040	0.086	0.086	-0.213	-0.067	3.172	0.189
16	1.000	-0.680	-0.640	0.320	0.040	0.084	0.084	-0.208	-0.061	3.426	0.187
17	1.000	-0.660	-0.680	0.340	0.040	0.082	0.082	-0.203	-0.055	3.700	0.184
18	1.000	-0.640	-0.720	0.360	0.040	0.079	0.079	-0.198	-0.050	3.996	0.180
19	1.000	-0.620	-0.760	0.380	0.040	0.077	0.077	-0.194	-0.045	4.316	0.176
20	1.000	-0.600	-0.800	0.400	0.040	0.074	0.074	-0.189	-0.041	4.661	0.172
21	1.000	-0.580	-0.840	0.420	0.040	0.072	0.072	-0.184	-0.037	5.034	0.167
22	1.000	-0.560	-0.880	0.440	0.040	0.070	0.070	-0.179	-0.033	5.437	0.162
23	1.000	-0.540	-0.920	0.460	0.040	0.067	0.067	-0.174	-0.030	5.871	0.157
24	1.000	-0.520	-0.960	0.480	0.040	0.065	0.065	-0.170	-0.027	6.341	0.151
25	1.000	-0.500	-1.000	0.500	0.040	0.062	0.062	-0.165	-0.024	6.848	0.146
							TOTAL	-5.560	-2.567		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #2-B1

FINANCING METHOD: PLACE ACCRUALS IN A FUND

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 12.00%
ON FUND: 0.0 %
TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.022	0.0	-0.022	0.0	0.022	0.022	0.0	-0.043	-0.040	1.080	0.020
2	0.045	0.0	-0.045	0.0	0.023	0.023	0.0	-0.047	-0.040	1.166	0.039
3	0.070	0.0	-0.070	0.0	0.025	0.025	0.0	-0.051	-0.040	1.260	0.056
4	0.098	0.0	-0.098	0.0	0.028	0.028	0.0	-0.055	-0.041	1.360	0.072
5	0.128	0.0	-0.128	0.0	0.030	0.030	0.0	-0.061	-0.041	1.469	0.087
6	0.162	0.0	-0.162	0.0	0.033	0.033	0.0	-0.066	-0.042	1.587	0.102
7	0.198	0.0	-0.198	0.0	0.037	0.037	0.0	-0.073	-0.043	1.714	0.116
8	0.239	0.0	-0.239	0.0	0.040	0.040	0.0	-0.081	-0.044	1.851	0.129
9	0.283	0.0	-0.283	0.0	0.045	0.045	0.0	-0.090	-0.045	1.999	0.142
10	0.333	0.0	-0.333	0.0	0.050	0.050	0.0	-0.100	-0.046	2.159	0.154
11	0.389	0.0	-0.389	0.0	0.056	0.056	0.0	-0.111	-0.048	2.332	0.167
12	0.451	0.0	-0.451	0.0	0.062	0.062	0.0	-0.124	-0.049	2.518	0.179
13	0.521	0.0	-0.521	0.0	0.070	0.070	0.0	-0.140	-0.051	2.720	0.191
14	0.600	0.0	-0.600	0.0	0.079	0.079	0.0	-0.158	-0.054	2.937	0.204
15	0.689	0.0	-0.689	0.0	0.090	0.090	0.0	-0.179	-0.057	3.172	0.217
16	0.792	0.0	-0.792	0.0	0.102	0.102	0.0	-0.205	-0.060	3.426	0.231
17	0.909	0.0	-0.909	0.0	0.118	0.118	0.0	-0.235	-0.064	3.700	0.246
18	1.045	0.0	-1.045	0.0	0.136	0.136	0.0	-0.272	-0.068	3.996	0.262
19	1.204	0.0	-1.204	0.0	0.159	0.159	0.0	-0.318	-0.074	4.316	0.279
20	1.392	0.0	-1.392	0.0	0.188	0.188	0.0	-0.375	-0.081	4.661	0.299
21	1.617	0.0	-1.617	0.0	0.225	0.225	0.0	-0.450	-0.089	5.034	0.321
22	1.892	0.0	-1.892	0.0	0.275	0.275	0.0	-0.551	-0.101	5.437	0.348
23	2.240	0.0	-2.240	0.0	0.348	0.348	0.0	-0.696	-0.118	5.871	0.382
24	2.705	0.0	-2.705	0.0	0.465	0.465	0.0	-0.930	-0.147	6.341	0.427
25	3.424	0.0	-3.424	0.0	0.719	0.719	0.0	-1.438	-0.210	6.848	0.500
							TOTAL	-6.848	-1.692		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #2-B2

FINANCING METHOD: PLACE ACCRUALS IN A FUND

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO ESTIMATED DATE OF RETIREMENT.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 12.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.137	0.0	-0.137	0.0	0.137	0.137	0.0	-0.274	-0.254	1.080	0.127
2	0.274	0.0	-0.274	0.0	0.137	0.137	0.0	-0.274	-0.235	1.166	0.235
3	0.411	0.0	-0.411	0.0	0.137	0.137	0.0	-0.274	-0.217	1.260	0.326
4	0.548	0.0	-0.548	0.0	0.137	0.137	0.0	-0.274	-0.201	1.360	0.403
5	0.685	0.0	-0.685	0.0	0.137	0.137	0.0	-0.274	-0.186	1.469	0.466
6	0.822	0.0	-0.822	0.0	0.137	0.137	0.0	-0.274	-0.173	1.587	0.518
7	0.959	0.0	-0.959	0.0	0.137	0.137	0.0	-0.274	-0.160	1.714	0.559
8	1.096	0.0	-1.096	0.0	0.137	0.137	0.0	-0.274	-0.148	1.851	0.592
9	1.233	0.0	-1.233	0.0	0.137	0.137	0.0	-0.274	-0.137	1.999	0.617
10	1.370	0.0	-1.370	0.0	0.137	0.137	0.0	-0.274	-0.127	2.159	0.634
11	1.507	0.0	-1.507	0.0	0.137	0.137	0.0	-0.274	-0.117	2.332	0.646
12	1.644	0.0	-1.644	0.0	0.137	0.137	0.0	-0.274	-0.109	2.518	0.653
13	1.781	0.0	-1.781	0.0	0.137	0.137	0.0	-0.274	-0.101	2.720	0.655
14	1.918	0.0	-1.918	0.0	0.137	0.137	0.0	-0.274	-0.093	2.937	0.653
15	2.055	0.0	-2.055	0.0	0.137	0.137	0.0	-0.274	-0.086	3.172	0.648
16	2.192	0.0	-2.192	0.0	0.137	0.137	0.0	-0.274	-0.080	3.426	0.640
17	2.328	0.0	-2.328	0.0	0.137	0.137	0.0	-0.274	-0.074	3.700	0.629
18	2.465	0.0	-2.465	0.0	0.137	0.137	0.0	-0.274	-0.069	3.996	0.617
19	2.602	0.0	-2.602	0.0	0.137	0.137	0.0	-0.274	-0.063	4.316	0.603
20	2.739	0.0	-2.739	0.0	0.137	0.137	0.0	-0.274	-0.059	4.661	0.588
21	2.876	0.0	-2.876	0.0	0.137	0.137	0.0	-0.274	-0.054	5.034	0.571
22	3.013	0.0	-3.013	0.0	0.137	0.137	0.0	-0.274	-0.050	5.437	0.554
23	3.150	0.0	-3.150	0.0	0.137	0.137	0.0	-0.274	-0.047	5.871	0.537
24	3.287	0.0	-3.287	0.0	0.137	0.137	0.0	-0.274	-0.043	6.341	0.518
25	3.424	0.0	-3.424	0.0	0.137	0.137	0.0	-0.274	-0.040	6.848	0.500
							TOTAL	-6.848	-2.924		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #2-C1

FINANCING METHOD: PLACE ACCRUALS IN A FUND

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 12.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.043	-0.022	-0.043	0.022	0.043	0.0	0.0	-0.043	-0.040	1.080	0.040
2	0.090	-0.045	-0.090	0.045	0.047	0.003	0.003	-0.052	-0.045	1.166	0.077
3	0.141	-0.070	-0.141	0.070	0.051	0.005	0.005	-0.062	-0.049	1.260	0.112
4	0.196	-0.098	-0.196	0.098	0.055	0.008	0.008	-0.072	-0.053	1.360	0.144
5	0.257	-0.128	-0.257	0.128	0.061	0.012	0.012	-0.084	-0.057	1.469	0.175
6	0.323	-0.162	-0.323	0.162	0.066	0.015	0.015	-0.097	-0.061	1.587	0.204
7	0.397	-0.198	-0.397	0.198	0.073	0.019	0.019	-0.112	-0.065	1.714	0.231
8	0.477	-0.239	-0.477	0.239	0.081	0.024	0.024	-0.126	-0.069	1.851	0.258
9	0.567	-0.283	-0.567	0.283	0.090	0.029	0.029	-0.147	-0.073	1.999	0.284
10	0.666	-0.333	-0.666	0.333	0.100	0.034	0.034	-0.168	-0.078	2.159	0.309
11	0.777	-0.389	-0.777	0.389	0.111	0.040	0.040	-0.191	-0.082	2.332	0.333
12	0.902	-0.451	-0.902	0.451	0.124	0.047	0.047	-0.218	-0.086	2.518	0.358
13	1.042	-0.521	-1.042	0.521	0.140	0.054	0.054	-0.248	-0.091	2.720	0.383
14	1.200	-0.600	-1.200	0.600	0.158	0.062	0.062	-0.283	-0.096	2.937	0.408
15	1.379	-0.689	-1.379	0.689	0.179	0.072	0.072	-0.323	-0.102	3.172	0.435
16	1.584	-0.792	-1.584	0.792	0.205	0.083	0.083	-0.370	-0.108	3.426	0.462
17	1.819	-0.909	-1.819	0.909	0.235	0.095	0.095	-0.425	-0.115	3.700	0.492
18	2.091	-1.045	-2.091	1.045	0.272	0.109	0.109	-0.490	-0.123	3.996	0.523
19	2.409	-1.204	-2.409	1.204	0.318	0.125	0.125	-0.569	-0.132	4.316	0.558
20	2.784	-1.392	-2.784	1.392	0.375	0.145	0.145	-0.664	-0.143	4.661	0.597
21	3.234	-1.617	-3.234	1.617	0.450	0.167	0.167	-0.784	-0.156	5.034	0.642
22	3.785	-1.892	-3.785	1.892	0.551	0.194	0.194	-0.939	-0.173	5.437	0.696
23	4.480	-2.240	-4.480	2.240	0.696	0.227	0.227	-1.150	-0.196	5.871	0.763
24	5.411	-2.705	-5.411	2.705	0.930	0.269	0.269	-1.468	-0.232	6.341	0.853
25	6.848	-3.424	-6.848	3.424	1.438	0.325	0.325	-2.087	-0.306	6.848	1.000
							TOTAL	-11.175	-2.729		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #2-C2

FINANCING METHOD: PLACE ACCRUALS IN A FUND

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO ESTIMATED DATE OF RETIREMENT.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 12.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.274	-0.137	-0.274	0.137	0.274	0.0	0.0	-0.274	-0.254	1.080	0.254
2	0.548	-0.274	-0.548	0.274	0.274	0.016	0.016	-0.307	-0.263	1.166	0.470
3	0.822	-0.411	-0.822	0.411	0.274	0.033	0.033	-0.340	-0.270	1.260	0.652
4	1.096	-0.548	-1.096	0.548	0.274	0.049	0.049	-0.373	-0.274	1.360	0.805
5	1.370	-0.685	-1.370	0.685	0.274	0.066	0.066	-0.405	-0.276	1.469	0.932
6	1.644	-0.822	-1.644	0.822	0.274	0.082	0.082	-0.438	-0.276	1.587	1.036
7	1.918	-0.959	-1.918	0.959	0.274	0.099	0.099	-0.471	-0.275	1.714	1.119
8	2.192	-1.096	-2.192	1.096	0.274	0.115	0.115	-0.504	-0.272	1.851	1.184
9	2.465	-1.233	-2.465	1.233	0.274	0.131	0.131	-0.537	-0.269	1.999	1.233
10	2.739	-1.370	-2.739	1.370	0.274	0.148	0.148	-0.570	-0.264	2.159	1.269
11	3.013	-1.507	-3.013	1.507	0.274	0.164	0.164	-0.603	-0.258	2.332	1.292
12	3.287	-1.644	-3.287	1.644	0.274	0.181	0.181	-0.636	-0.252	2.518	1.305
13	3.561	-1.781	-3.561	1.781	0.274	0.197	0.197	-0.668	-0.246	2.720	1.309
14	3.835	-1.918	-3.835	1.918	0.274	0.214	0.214	-0.701	-0.239	2.937	1.306
15	4.109	-2.055	-4.109	2.055	0.274	0.230	0.230	-0.734	-0.231	3.172	1.295
16	4.383	-2.192	-4.383	2.192	0.274	0.247	0.247	-0.767	-0.224	3.426	1.279
17	4.657	-2.328	-4.657	2.328	0.274	0.263	0.263	-0.800	-0.216	3.700	1.259
18	4.931	-2.465	-4.931	2.465	0.274	0.279	0.279	-0.833	-0.208	3.996	1.234
19	5.205	-2.602	-5.205	2.602	0.274	0.296	0.296	-0.866	-0.201	4.316	1.206
20	5.479	-2.739	-5.479	2.739	0.274	0.312	0.312	-0.899	-0.193	4.661	1.175
21	5.753	-2.876	-5.753	2.876	0.274	0.329	0.329	-0.931	-0.185	5.034	1.143
22	6.027	-3.013	-6.027	3.013	0.274	0.345	0.345	-0.964	-0.177	5.437	1.109
23	6.301	-3.150	-6.301	3.150	0.274	0.362	0.362	-0.997	-0.170	5.871	1.073
24	6.575	-3.287	-6.575	3.287	0.274	0.378	0.378	-1.030	-0.162	6.341	1.037
25	6.848	-3.424	-6.848	3.424	0.274	0.394	0.394	-1.063	-0.155	6.848	1.000
							TOTAL	-16.710	-5.811		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #3-81

FINANCING METHOD: FINANCE AT DECOMMISSIONING

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 12.00%

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%

RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.0	0.022	-0.022	0.0	0.022	0.022	0.0	-0.043	-0.040	1.080	0.020
2	0.0	0.045	-0.045	0.0	0.023	0.021	-0.003	-0.042	-0.036	1.166	0.039
3	0.0	0.070	-0.070	0.0	0.025	0.020	-0.005	-0.040	-0.032	1.260	0.056
4	0.0	0.098	-0.098	0.0	0.028	0.019	-0.008	-0.039	-0.028	1.360	0.072
5	0.0	0.128	-0.128	0.0	0.030	0.019	-0.012	-0.037	-0.025	1.469	0.087
6	0.0	0.162	-0.162	0.0	0.033	0.018	-0.015	-0.036	-0.022	1.587	0.102
7	0.0	0.198	-0.198	0.0	0.037	0.017	-0.019	-0.034	-0.020	1.714	0.116
8	0.0	0.239	-0.239	0.0	0.040	0.017	-0.024	-0.033	-0.018	1.851	0.129
9	0.0	0.283	-0.283	0.0	0.045	0.016	-0.029	-0.032	-0.016	1.999	0.142
10	0.0	0.333	-0.333	0.0	0.050	0.016	-0.034	-0.031	-0.015	2.159	0.154
11	0.0	0.389	-0.389	0.0	0.056	0.016	-0.040	-0.031	-0.013	2.332	0.167
12	0.0	0.451	-0.451	0.0	0.062	0.016	-0.047	-0.031	-0.012	2.518	0.179
13	0.0	0.521	-0.521	0.0	0.070	0.016	-0.054	-0.032	-0.012	2.720	0.191
14	0.0	0.600	-0.600	0.0	0.079	0.016	-0.062	-0.033	-0.011	2.937	0.204
15	0.0	0.689	-0.689	0.0	0.090	0.018	-0.072	-0.035	-0.011	3.172	0.217
16	0.0	0.792	-0.792	0.0	0.102	0.020	-0.083	-0.039	-0.011	3.426	0.231
17	0.0	0.909	-0.909	0.0	0.118	0.023	-0.095	-0.045	-0.012	3.700	0.246
18	0.0	1.045	-1.045	0.0	0.136	0.027	-0.109	-0.054	-0.013	3.996	0.262
19	0.0	1.204	-1.204	0.0	0.159	0.033	-0.125	-0.067	-0.016	4.316	0.279
20	0.0	1.392	-1.392	0.0	0.188	0.043	-0.145	-0.086	-0.019	4.661	0.299
21	0.0	1.617	-1.617	0.0	0.225	0.058	-0.167	-0.116	-0.023	5.034	0.321
22	0.0	1.892	-1.892	0.0	0.275	0.081	-0.194	-0.163	-0.030	5.437	0.348
23	0.0	2.240	-2.240	0.0	0.348	0.121	-0.227	-0.241	-0.041	5.871	0.382
24	0.0	2.705	-2.705	0.0	0.465	0.196	-0.269	-0.393	-0.062	6.341	0.427
25	0.0	3.424	-3.424	0.0	0.719	0.394	-0.325	-0.788	-0.115	6.848	0.500
							TOTAL	-2.522	-0.654		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #3-B2

FINANCING METHOD: FINANCE AT DECOMMISSIONING

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO ESTIMATED DATE OF RETIREMENT.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 12.00%

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%

RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.0	0.137	-0.137	0.0	0.137	0.137	0.0	-0.274	-0.254	1.080	0.127
2	0.0	0.274	-0.274	0.0	0.137	0.121	-0.016	-0.241	-0.207	1.166	0.235
3	0.0	0.411	-0.411	0.0	0.137	0.104	-0.033	-0.208	-0.165	1.260	0.326
4	0.0	0.548	-0.548	0.0	0.137	0.088	-0.049	-0.175	-0.129	1.360	0.403
5	0.0	0.685	-0.685	0.0	0.137	0.071	-0.066	-0.142	-0.097	1.469	0.466
6	0.0	0.822	-0.822	0.0	0.137	0.055	-0.082	-0.110	-0.069	1.587	0.518
7	0.0	0.959	-0.959	0.0	0.137	0.038	-0.099	-0.077	-0.045	1.714	0.559
8	0.0	1.096	-1.096	0.0	0.137	0.022	-0.115	-0.044	-0.024	1.851	0.592
9	0.0	1.233	-1.233	0.0	0.137	0.005	-0.131	-0.011	-0.005	1.999	0.617
10	0.0	1.370	-1.370	0.0	0.137	-0.011	-0.148	0.022	0.010	2.159	0.634
11	0.0	1.507	-1.507	0.0	0.137	-0.027	-0.164	0.055	0.023	2.332	0.646
12	0.0	1.644	-1.644	0.0	0.137	-0.044	-0.181	0.088	0.035	2.518	0.653
13	0.0	1.781	-1.781	0.0	0.137	-0.060	-0.197	0.121	0.044	2.720	0.655
14	0.0	1.918	-1.918	0.0	0.137	-0.077	-0.214	0.153	0.052	2.937	0.653
15	0.0	2.055	-2.055	0.0	0.137	-0.093	-0.230	0.186	0.059	3.172	0.648
16	0.0	2.192	-2.192	0.0	0.137	-0.110	-0.247	0.219	0.064	3.426	0.640
17	0.0	2.328	-2.328	0.0	0.137	-0.126	-0.263	0.252	0.068	3.700	0.629
18	0.0	2.465	-2.465	0.0	0.137	-0.142	-0.279	0.285	0.071	3.996	0.617
19	0.0	2.602	-2.602	0.0	0.137	-0.159	-0.296	0.318	0.074	4.316	0.603
20	0.0	2.739	-2.739	0.0	0.137	-0.175	-0.312	0.351	0.075	4.661	0.588
21	0.0	2.876	-2.876	0.0	0.137	-0.192	-0.329	0.384	0.076	5.034	0.571
22	0.0	3.013	-3.013	0.0	0.137	-0.208	-0.345	0.416	0.077	5.437	0.554
23	0.0	3.150	-3.150	0.0	0.137	-0.225	-0.362	0.449	0.077	5.871	0.537
24	0.0	3.287	-3.287	0.0	0.137	-0.241	-0.378	0.482	0.076	6.341	0.518
25	0.0	3.424	-3.424	0.0	0.137	-0.258	-0.394	0.515	0.075	6.848	0.500
							TOTAL	3.013	-0.038		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #3-C1

FINANCING METHOD: FINANCE AT DECOMMISSIONING | RATE OF RETURN ON CAPITAL: 12.00%

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING | TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 8.00%

RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.0	0.022	-0.043	0.022	0.043	0.0	0.0	-0.043	-0.040	1.080	0.040
2	0.0	0.045	-0.090	0.045	0.047	-0.003	-0.003	-0.042	-0.036	1.166	0.077
3	0.0	0.070	-0.141	0.070	0.051	-0.005	-0.005	-0.040	-0.032	1.260	0.112
4	0.0	0.098	-0.196	0.098	0.055	-0.008	-0.008	-0.039	-0.028	1.360	0.144
5	0.0	0.128	-0.257	0.128	0.061	-0.012	-0.012	-0.037	-0.025	1.469	0.175
6	0.0	0.162	-0.323	0.162	0.066	-0.015	-0.015	-0.036	-0.022	1.587	0.204
7	0.0	0.198	-0.397	0.198	0.073	-0.019	-0.019	-0.034	-0.020	1.714	0.231
8	0.0	0.239	-0.477	0.239	0.081	-0.024	-0.024	-0.033	-0.018	1.851	0.258
9	0.0	0.283	-0.567	0.283	0.090	-0.029	-0.029	-0.032	-0.016	1.999	0.284
10	0.0	0.333	-0.666	0.333	0.100	-0.034	-0.034	-0.031	-0.015	2.159	0.309
11	0.0	0.389	-0.777	0.389	0.111	-0.040	-0.040	-0.031	-0.013	2.332	0.333
12	0.0	0.451	-0.902	0.451	0.124	-0.047	-0.047	-0.031	-0.012	2.518	0.358
13	0.0	0.521	-1.042	0.521	0.140	-0.054	-0.054	-0.032	-0.012	2.720	0.383
14	0.0	0.600	-1.200	0.600	0.158	-0.062	-0.062	-0.033	-0.011	2.937	0.408
15	0.0	0.689	-1.379	0.689	0.179	-0.072	-0.072	-0.035	-0.011	3.172	0.435
16	0.0	0.792	-1.584	0.792	0.205	-0.083	-0.083	-0.039	-0.011	3.426	0.462
17	0.0	0.909	-1.819	0.909	0.235	-0.095	-0.095	-0.045	-0.012	3.700	0.492
18	0.0	1.045	-2.091	1.045	0.272	-0.109	-0.109	-0.054	-0.013	3.996	0.523
19	0.0	1.204	-2.409	1.204	0.318	-0.125	-0.125	-0.067	-0.016	4.316	0.558
20	0.0	1.392	-2.784	1.392	0.375	-0.145	-0.145	-0.086	-0.019	4.661	0.597
21	0.0	1.617	-3.234	1.617	0.450	-0.167	-0.167	-0.116	-0.023	5.034	0.642
22	0.0	1.892	-3.785	1.892	0.551	-0.194	-0.194	-0.163	-0.030	5.437	0.696
23	0.0	2.240	-4.480	2.240	0.696	-0.227	-0.227	-0.241	-0.041	5.871	0.763
24	0.0	2.705	-5.411	2.705	0.930	-0.269	-0.269	-0.393	-0.062	6.341	0.853
25	0.0	3.424	-6.848	3.424	1.438	-0.325	-0.325	-0.788	-0.115	6.848	1.000
							TOTAL	-2.522	-0.654		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #3-C2

FINANCING METHOD: FINANCE AT DECOMMISSIONING

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO ESTIMATED DATE OF RETIREMENT.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 12.00%

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%

RESERVE COMPOUNDED AT 0.0 %

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.0	0.137	-0.274	0.137	0.274	0.0	0.0	-0.274	-0.254	1.080	0.254
2	0.0	0.274	-0.548	0.274	0.274	-0.016	-0.016	-0.241	-0.207	1.166	0.470
3	0.0	0.411	-0.822	0.411	0.274	-0.033	-0.033	-0.208	-0.165	1.260	0.652
4	0.0	0.548	-1.096	0.548	0.274	-0.049	-0.049	-0.175	-0.129	1.360	0.805
5	0.0	0.685	-1.370	0.685	0.274	-0.066	-0.066	-0.142	-0.097	1.469	0.932
6	0.0	0.822	-1.644	0.822	0.274	-0.082	-0.082	-0.110	-0.069	1.587	1.036
7	0.0	0.959	-1.918	0.959	0.274	-0.099	-0.099	-0.077	-0.045	1.714	1.119
8	0.0	1.096	-2.192	1.096	0.274	-0.115	-0.115	-0.044	-0.024	1.851	1.184
9	0.0	1.233	-2.465	1.233	0.274	-0.131	-0.131	-0.011	-0.005	1.999	1.233
10	0.0	1.370	-2.739	1.370	0.274	-0.148	-0.148	0.022	0.010	2.159	1.269
11	0.0	1.507	-3.013	1.507	0.274	-0.164	-0.164	0.055	0.023	2.332	1.292
12	0.0	1.644	-3.287	1.644	0.274	-0.181	-0.181	0.088	0.035	2.518	1.305
13	0.0	1.781	-3.561	1.781	0.274	-0.197	-0.197	0.121	0.044	2.720	1.309
14	0.0	1.918	-3.835	1.918	0.274	-0.214	-0.214	0.153	0.052	2.937	1.306
15	0.0	2.055	-4.109	2.055	0.274	-0.230	-0.230	0.186	0.059	3.172	1.295
16	0.0	2.192	-4.383	2.192	0.274	-0.247	-0.247	0.219	0.064	3.426	1.279
17	0.0	2.328	-4.657	2.328	0.274	-0.263	-0.263	0.252	0.068	3.700	1.259
18	0.0	2.465	-4.931	2.465	0.274	-0.279	-0.279	0.285	0.071	3.996	1.234
19	0.0	2.602	-5.205	2.602	0.274	-0.296	-0.296	0.318	0.074	4.316	1.206
20	0.0	2.739	-5.479	2.739	0.274	-0.312	-0.312	0.351	0.075	4.661	1.175
21	0.0	2.876	-5.753	2.876	0.274	-0.329	-0.329	0.384	0.076	5.034	1.143
22	0.0	3.013	-6.027	3.013	0.274	-0.345	-0.345	0.416	0.077	5.437	1.109
23	0.0	3.150	-6.301	3.150	0.274	-0.362	-0.362	0.449	0.077	5.871	1.073
24	0.0	3.287	-6.575	3.287	0.274	-0.378	-0.378	0.482	0.076	6.341	1.037
25	0.0	3.424	-6.848	3.424	0.274	-0.394	-0.394	0.515	0.075	6.848	1.000
							TOTAL	3.013	-0.038		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #1- 3

FINANCING METHOD: ESTABLISH FUND AT AGE ZERO
TAX ACCOUNTING METHOD: NOT APPLICABLE
CAPITAL REQUIRED TO ESTABLISH FUND AT AGE ZERO AMORTIZED OVER THE PLANT LIFE.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %
TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 0.0 %
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	1.000	-1.000									
1	1.000	-0.960	-0.040	0.0	0.040	0.040	0.040	-0.120	-0.111	1.080	0.037
2	1.000	-0.917	-0.083	0.0	0.043	0.038	0.038	-0.120	-0.103	1.166	0.071
3	1.000	-0.871	-0.129	0.0	0.046	0.037	0.037	-0.120	-0.095	1.260	0.103
4	1.000	-0.821	-0.179	0.0	0.049	0.035	0.035	-0.119	-0.088	1.360	0.131
5	1.000	-0.769	-0.231	0.0	0.053	0.033	0.033	-0.118	-0.081	1.469	0.158
6	1.000	-0.713	-0.287	0.0	0.056	0.031	0.031	-0.118	-0.074	1.587	0.181
7	1.000	-0.653	-0.347	0.0	0.059	0.029	0.029	-0.116	-0.068	1.714	0.202
8	1.000	-0.591	-0.409	0.0	0.062	0.026	0.026	-0.115	-0.062	1.851	0.221
9	1.000	-0.525	-0.475	0.0	0.066	0.024	0.024	-0.113	-0.056	1.999	0.238
10	1.000	-0.457	-0.543	0.0	0.068	0.021	0.021	-0.110	-0.051	2.159	0.252
11	1.000	-0.386	-0.614	0.0	0.071	0.018	0.018	-0.108	-0.046	2.332	0.263
12	1.000	-0.313	-0.687	0.0	0.073	0.015	0.015	-0.104	-0.041	2.518	0.273
13	1.000	-0.238	-0.762	0.0	0.075	0.013	0.013	-0.100	-0.037	2.720	0.280
14	1.000	-0.162	-0.838	0.0	0.076	0.010	0.010	-0.095	-0.032	2.937	0.285
15	1.000	-0.086	-0.914	0.0	0.076	0.006	0.006	-0.089	-0.028	3.172	0.288
16	1.000	-0.012	-0.988	0.0	0.074	0.003	0.003	-0.081	-0.024	3.426	0.288
17	1.000	0.060	-1.060	0.0	0.072	0.000	0.000	-0.073	-0.020	3.700	0.286
18	1.000	0.126	-1.126	0.0	0.067	-0.002	-0.002	-0.062	-0.016	3.996	0.282
19	1.000	0.186	-1.186	0.0	0.059	-0.005	-0.005	-0.049	-0.011	4.316	0.275
20	1.000	0.234	-1.234	0.0	0.048	-0.007	-0.007	-0.033	-0.007	4.661	0.265
21	1.000	0.266	-1.266	0.0	0.032	-0.009	-0.009	-0.014	-0.003	5.034	0.251
22	1.000	0.275	-1.275	0.0	0.009	-0.011	-0.011	0.012	0.002	5.437	0.235
23	1.000	0.252	-1.252	0.0	-0.024	-0.011	-0.011	0.046	0.008	5.871	0.213
24	1.000	0.176	-1.176	0.0	-0.076	-0.010	-0.010	0.096	0.015	6.341	0.185
25	1.000	0.000	-1.000	0.0	-0.176	-0.007	-0.007	0.190	0.028	6.848	0.146
							TOTAL	-1.632	-1.000		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #1- 4

FINANCING METHOD: ESTABLISH FUND AT AGE ZERO

TAX ACCOUNTING METHOD: NOT APPLICABLE

CAPITAL REQUIRED TO ESTABLISH FUND AT AGE ZERO
AMORTIZED OVER THE PLANT LIFE.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 0.0 %
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	1.000	-1.000			0.040	0.040	0.040	-0.120	-0.111	1.080	0.037
1	1.000	-0.960	-0.040	0.0	0.040	0.038	0.038	-0.120	-0.103	1.166	0.071
2	1.000	-0.917	-0.083	0.0	0.043	0.037	0.037	-0.120	-0.095	1.260	0.103
3	1.000	-0.871	-0.129	0.0	0.046	0.035	0.035	-0.119	-0.088	1.360	0.131
4	1.000	-0.821	-0.179	0.0	0.049	0.033	0.033	-0.118	-0.081	1.469	0.158
5	1.000	-0.769	-0.231	0.0	0.053	0.031	0.031	-0.118	-0.074	1.587	0.181
6	1.000	-0.713	-0.287	0.0	0.056	0.029	0.029	-0.116	-0.068	1.714	0.202
7	1.000	-0.653	-0.347	0.0	0.059	0.026	0.026	-0.115	-0.062	1.851	0.221
8	1.000	-0.591	-0.409	0.0	0.062	0.024	0.024	-0.113	-0.056	1.999	0.238
9	1.000	-0.525	-0.475	0.0	0.066	0.021	0.021	-0.110	-0.051	2.159	0.252
10	1.000	-0.457	-0.543	0.0	0.068	0.018	0.018	-0.108	-0.046	2.332	0.263
11	1.000	-0.386	-0.614	0.0	0.071	0.015	0.015	-0.104	-0.041	2.518	0.273
12	1.000	-0.313	-0.687	0.0	0.073	0.013	0.013	-0.100	-0.037	2.720	0.280
13	1.000	-0.238	-0.762	0.0	0.075	0.010	0.010	-0.095	-0.032	2.937	0.285
14	1.000	-0.162	-0.838	0.0	0.076	0.006	0.006	-0.089	-0.028	3.172	0.288
15	1.000	-0.086	-0.914	0.0	0.076	0.003	0.003	-0.081	-0.024	3.426	0.288
16	1.000	-0.012	-0.988	0.0	0.074	0.000	0.000	-0.073	-0.020	3.700	0.286
17	1.000	0.060	-1.060	0.0	0.072	-0.002	-0.002	-0.062	-0.016	3.996	0.282
18	1.000	0.126	-1.126	0.0	0.067	-0.005	-0.005	-0.049	-0.011	4.316	0.275
19	1.000	0.186	-1.186	0.0	0.059	-0.007	-0.007	-0.033	-0.007	4.661	0.265
20	1.000	0.234	-1.234	0.0	0.048	-0.009	-0.009	-0.014	-0.003	5.034	0.251
21	1.000	0.266	-1.266	0.0	0.032	-0.011	-0.011	0.012	0.002	5.437	0.235
22	1.000	0.275	-1.275	0.0	0.009	-0.011	-0.011	0.046	0.008	5.871	0.213
23	1.000	0.252	-1.252	0.0	-0.024	-0.010	-0.010	0.096	0.015	6.341	0.185
24	1.000	0.176	-1.176	0.0	-0.076	-0.007	-0.007	0.190	0.028	6.848	0.146
25	1.000	0.000	-1.000	0.0	-0.176						
							TOTAL	-1.632	-1.000		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #1-B3

FINANCING METHOD: ESTABLISH FUND AT AGE ZERO

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

CAPITAL REQUIRED TO ESTABLISH FUND AT AGE ZERO
AMORTIZED OVER THE PLANT LIFE.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.500	-0.500									
1	0.500	-0.480	-0.020	0.0	0.020	0.040	0.020	-0.080	-0.074	1.080	0.019
2	0.500	-0.458	-0.042	0.0	0.022	0.041	0.019	-0.081	-0.070	1.166	0.036
3	0.500	-0.435	-0.065	0.0	0.023	0.041	0.018	-0.083	-0.066	1.260	0.051
4	0.500	-0.411	-0.089	0.0	0.025	0.042	0.017	-0.084	-0.062	1.360	0.066
5	0.500	-0.384	-0.116	0.0	0.026	0.043	0.016	-0.086	-0.058	1.469	0.079
6	0.500	-0.356	-0.144	0.0	0.028	0.043	0.015	-0.087	-0.055	1.587	0.091
7	0.500	-0.327	-0.173	0.0	0.030	0.044	0.014	-0.088	-0.051	1.714	0.101
8	0.500	-0.295	-0.205	0.0	0.031	0.044	0.013	-0.089	-0.048	1.851	0.111
9	0.500	-0.263	-0.237	0.0	0.033	0.045	0.012	-0.089	-0.045	1.999	0.119
10	0.500	-0.228	-0.272	0.0	0.034	0.045	0.011	-0.089	-0.041	2.159	0.126
11	0.500	-0.193	-0.307	0.0	0.036	0.045	0.009	-0.089	-0.038	2.332	0.132
12	0.500	-0.156	-0.344	0.0	0.037	0.044	0.008	-0.089	-0.035	2.518	0.137
13	0.500	-0.119	-0.381	0.0	0.037	0.044	0.006	-0.087	-0.032	2.720	0.140
14	0.500	-0.081	-0.419	0.0	0.038	0.043	0.005	-0.085	-0.029	2.937	0.143
15	0.500	-0.043	-0.457	0.0	0.038	0.041	0.003	-0.082	-0.026	3.172	0.144
16	0.500	-0.006	-0.494	0.0	0.037	0.039	0.002	-0.078	-0.023	3.426	0.144
17	0.500	0.030	-0.530	0.0	0.036	0.036	0.000	-0.072	-0.019	3.700	0.143
18	0.500	0.063	-0.563	0.0	0.033	0.032	-0.001	-0.064	-0.016	3.996	0.141
19	0.500	0.093	-0.593	0.0	0.030	0.027	-0.003	-0.054	-0.013	4.316	0.137
20	0.500	0.117	-0.617	0.0	0.024	0.020	-0.004	-0.041	-0.009	4.661	0.132
21	0.500	0.133	-0.633	0.0	0.016	0.011	-0.005	-0.023	-0.005	5.034	0.126
22	0.500	0.138	-0.638	0.0	0.005	-0.001	-0.005	0.001	0.000	5.437	0.117
23	0.500	0.126	-0.626	0.0	-0.012	-0.017	-0.006	0.035	0.006	5.871	0.107
24	0.500	0.088	-0.588	0.0	-0.038	-0.043	-0.005	0.086	0.014	6.341	0.093
25	0.500	0.000	-0.500	0.0	-0.088	-0.091	-0.004	0.183	0.027	6.848	0.073
							TOTAL	-1.316	-0.768		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #1-B4

FINANCING METHOD: ESTABLISH FUND AT AGE ZERO

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

CAPITAL REQUIRED TO ESTABLISH FUND AT AGE ZERO
AMORTIZED OVER THE PLANT LIFE.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.500	-0.500									
1	0.500	-0.480	-0.020	0.0	0.020	0.040	0.020	-0.080	-0.074	1.080	0.019
2	0.500	-0.458	-0.042	0.0	0.022	0.041	0.019	-0.081	-0.070	1.166	0.036
3	0.500	-0.435	-0.065	0.0	0.023	0.041	0.018	-0.083	-0.066	1.260	0.051
4	0.500	-0.411	-0.089	0.0	0.025	0.042	0.017	-0.084	-0.062	1.360	0.066
5	0.500	-0.384	-0.116	0.0	0.026	0.043	0.016	-0.086	-0.058	1.469	0.079
6	0.500	-0.356	-0.144	0.0	0.028	0.043	0.015	-0.087	-0.055	1.587	0.091
7	0.500	-0.327	-0.173	0.0	0.030	0.044	0.014	-0.088	-0.051	1.714	0.101
8	0.500	-0.295	-0.205	0.0	0.031	0.044	0.013	-0.089	-0.048	1.851	0.111
9	0.500	-0.263	-0.237	0.0	0.033	0.045	0.012	-0.089	-0.045	1.999	0.119
10	0.500	-0.228	-0.272	0.0	0.034	0.045	0.011	-0.089	-0.041	2.159	0.126
11	0.500	-0.193	-0.307	0.0	0.036	0.045	0.009	-0.089	-0.038	2.332	0.132
12	0.500	-0.156	-0.344	0.0	0.037	0.044	0.008	-0.089	-0.035	2.518	0.137
13	0.500	-0.119	-0.381	0.0	0.037	0.044	0.006	-0.087	-0.032	2.720	0.140
14	0.500	-0.081	-0.419	0.0	0.038	0.043	0.005	-0.085	-0.029	2.937	0.143
15	0.500	-0.043	-0.457	0.0	0.038	0.041	0.003	-0.082	-0.026	3.172	0.144
16	0.500	-0.006	-0.494	0.0	0.037	0.039	0.002	-0.078	-0.023	3.426	0.144
17	0.500	0.030	-0.530	0.0	0.036	0.036	0.000	-0.072	-0.019	3.700	0.143
18	0.500	0.063	-0.563	0.0	0.033	0.032	-0.001	-0.064	-0.016	3.996	0.141
19	0.500	0.093	-0.593	0.0	0.030	0.027	-0.003	-0.054	-0.013	4.316	0.137
20	0.500	0.117	-0.617	0.0	0.024	0.020	-0.004	-0.041	-0.009	4.661	0.132
21	0.500	0.133	-0.633	0.0	0.016	0.011	-0.005	-0.023	-0.005	5.034	0.126
22	0.500	0.138	-0.638	0.0	0.005	-0.001	-0.005	0.001	0.000	5.437	0.117
23	0.500	0.126	-0.626	0.0	-0.012	-0.017	-0.006	0.035	0.006	5.871	0.107
24	0.500	0.088	-0.588	0.0	-0.038	-0.043	-0.005	0.086	0.014	6.341	0.093
25	0.500	0.000	-0.500	0.0	-0.088	-0.091	-0.004	0.183	0.027	6.848	0.073
							TOTAL	-1.316	-0.768		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #1-C3

FINANCING METHOD: ESTABLISH FUND AT AGE ZERO

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

CAPITAL REQUIRED TO ESTABLISH FUND AT AGE ZERO
AMORTIZED OVER THE PLANT LIFE.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	1.000	-1.000									
1	1.000	-0.980	-0.040	0.020	0.040	0.040	0.040	-0.120	-0.111	1.080	0.037
2	1.000	-0.958	-0.083	0.042	0.043	0.039	0.039	-0.121	-0.104	1.166	0.071
3	1.000	-0.935	-0.129	0.065	0.046	0.038	0.038	-0.123	-0.098	1.260	0.103
4	1.000	-0.911	-0.179	0.089	0.049	0.037	0.037	-0.124	-0.091	1.360	0.131
5	1.000	-0.884	-0.231	0.116	0.053	0.036	0.036	-0.126	-0.085	1.469	0.158
6	1.000	-0.856	-0.287	0.144	0.056	0.035	0.035	-0.127	-0.080	1.587	0.181
7	1.000	-0.827	-0.347	0.173	0.059	0.034	0.034	-0.128	-0.075	1.714	0.202
8	1.000	-0.795	-0.409	0.205	0.062	0.033	0.033	-0.129	-0.069	1.851	0.221
9	1.000	-0.763	-0.475	0.237	0.066	0.032	0.032	-0.129	-0.065	1.999	0.238
10	1.000	-0.728	-0.543	0.272	0.068	0.031	0.031	-0.129	-0.060	2.159	0.252
11	1.000	-0.693	-0.614	0.307	0.071	0.029	0.029	-0.129	-0.055	2.332	0.263
12	1.000	-0.656	-0.687	0.344	0.073	0.028	0.028	-0.129	-0.051	2.518	0.273
13	1.000	-0.619	-0.762	0.381	0.075	0.026	0.026	-0.127	-0.047	2.720	0.280
14	1.000	-0.581	-0.838	0.419	0.076	0.025	0.025	-0.125	-0.043	2.937	0.285
15	1.000	-0.543	-0.914	0.457	0.076	0.023	0.023	-0.122	-0.039	3.172	0.288
16	1.000	-0.506	-0.988	0.494	0.074	0.022	0.022	-0.118	-0.034	3.426	0.288
17	1.000	-0.470	-1.060	0.530	0.072	0.020	0.020	-0.112	-0.030	3.700	0.286
18	1.000	-0.437	-1.126	0.563	0.067	0.019	0.019	-0.104	-0.026	3.996	0.282
19	1.000	-0.407	-1.186	0.593	0.059	0.017	0.017	-0.094	-0.022	4.316	0.275
20	1.000	-0.383	-1.234	0.617	0.048	0.016	0.016	-0.081	-0.017	4.661	0.265
21	1.000	-0.367	-1.266	0.633	0.032	0.015	0.015	-0.063	-0.012	5.034	0.251
22	1.000	-0.362	-1.275	0.638	0.009	0.015	0.015	-0.039	-0.007	5.437	0.235
23	1.000	-0.374	-1.252	0.626	-0.024	0.014	0.014	-0.005	-0.001	5.871	0.213
24	1.000	-0.412	-1.176	0.588	-0.076	0.015	0.015	0.046	0.007	6.341	0.185
25	1.000	-0.500	-1.000	0.500	-0.176	0.016	0.016	0.143	0.021	6.848	0.146
							TOTAL	-2.316	-1.195		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #1-C4

FINANCING METHOD: ESTABLISH FUND AT AGE ZERO

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

CAPITAL REQUIRED TO ESTABLISH FUND AT AGE ZERO
AMORTIZED OVER THE PLANT LIFE.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %
TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	1.000	-1.000									
1	1.000	-0.980	-0.040	0.020	0.040	0.040	0.040	-0.120	-0.111	1.080	0.037
2	1.000	-0.958	-0.083	0.042	0.043	0.039	0.039	-0.121	-0.104	1.166	0.071
3	1.000	-0.935	-0.129	0.065	0.046	0.038	0.038	-0.123	-0.098	1.260	0.103
4	1.000	-0.911	-0.179	0.089	0.049	0.037	0.037	-0.124	-0.091	1.360	0.131
5	1.000	-0.884	-0.231	0.116	0.053	0.036	0.036	-0.126	-0.085	1.469	0.158
6	1.000	-0.856	-0.287	0.144	0.056	0.035	0.035	-0.127	-0.080	1.587	0.181
7	1.000	-0.827	-0.347	0.173	0.059	0.034	0.034	-0.128	-0.075	1.714	0.202
8	1.000	-0.795	-0.409	0.205	0.062	0.033	0.033	-0.129	-0.069	1.851	0.221
9	1.000	-0.763	-0.475	0.237	0.066	0.032	0.032	-0.129	-0.065	1.999	0.238
10	1.000	-0.728	-0.543	0.272	0.068	0.031	0.031	-0.129	-0.060	2.159	0.252
11	1.000	-0.693	-0.614	0.307	0.071	0.029	0.029	-0.129	-0.055	2.332	0.263
12	1.000	-0.656	-0.687	0.344	0.073	0.028	0.028	-0.129	-0.051	2.518	0.273
13	1.000	-0.619	-0.762	0.381	0.075	0.026	0.026	-0.127	-0.047	2.720	0.280
14	1.000	-0.581	-0.838	0.419	0.076	0.025	0.025	-0.125	-0.043	2.937	0.285
15	1.000	-0.543	-0.914	0.457	0.076	0.023	0.023	-0.122	-0.039	3.172	0.288
16	1.000	-0.506	-0.988	0.494	0.074	0.022	0.022	-0.118	-0.034	3.426	0.288
17	1.000	-0.470	-1.060	0.530	0.072	0.020	0.020	-0.112	-0.030	3.700	0.286
18	1.000	-0.437	-1.126	0.563	0.067	0.019	0.019	-0.104	-0.026	3.996	0.282
19	1.000	-0.407	-1.186	0.593	0.059	0.017	0.017	-0.094	-0.022	4.316	0.275
20	1.000	-0.383	-1.234	0.617	0.048	0.016	0.016	-0.081	-0.017	4.661	0.265
21	1.000	-0.367	-1.266	0.633	0.032	0.015	0.015	-0.063	-0.012	5.034	0.251
22	1.000	-0.362	-1.275	0.638	0.009	0.015	0.015	-0.039	-0.007	5.437	0.235
23	1.000	-0.374	-1.252	0.626	-0.024	0.014	0.014	-0.005	-0.001	5.871	0.213
24	1.000	-0.412	-1.176	0.588	-0.076	0.015	0.015	0.046	0.007	6.341	0.185
25	1.000	-0.500	-1.000	0.500	-0.176	0.016	0.016	0.143	0.021	6.848	0.146
							TOTAL	-2.316	-1.195		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #2- 3

FINANCING METHOD: PLACE ACCRUALS IN A FUND

TAX ACCOUNTING METHOD: NOT APPLICABLE

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 0.0 %
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.043	0.0	-0.043	0.0	0.043	0.0	0.0	-0.043	-0.040	1.080	0.040
2	0.093	0.0	-0.093	0.0	0.050	0.0	0.0	-0.050	-0.043	1.166	0.080
3	0.151	0.0	-0.151	0.0	0.058	0.0	0.0	-0.058	-0.046	1.260	0.120
4	0.218	0.0	-0.218	0.0	0.067	0.0	0.0	-0.067	-0.049	1.360	0.160
5	0.294	0.0	-0.294	0.0	0.076	0.0	0.0	-0.076	-0.052	1.469	0.200
6	0.381	0.0	-0.381	0.0	0.087	0.0	0.0	-0.087	-0.055	1.587	0.240
7	0.480	0.0	-0.480	0.0	0.099	0.0	0.0	-0.099	-0.058	1.714	0.280
8	0.592	0.0	-0.592	0.0	0.112	0.0	0.0	-0.112	-0.061	1.851	0.320
9	0.720	0.0	-0.720	0.0	0.127	0.0	0.0	-0.127	-0.064	1.999	0.360
10	0.864	0.0	-0.864	0.0	0.144	0.0	0.0	-0.144	-0.067	2.159	0.400
11	1.026	0.0	-1.026	0.0	0.162	0.0	0.0	-0.162	-0.070	2.332	0.440
12	1.209	0.0	-1.209	0.0	0.183	0.0	0.0	-0.183	-0.073	2.518	0.480
13	1.414	0.0	-1.414	0.0	0.205	0.0	0.0	-0.205	-0.076	2.720	0.520
14	1.645	0.0	-1.645	0.0	0.231	0.0	0.0	-0.231	-0.079	2.937	0.560
15	1.903	0.0	-1.903	0.0	0.258	0.0	0.0	-0.258	-0.081	3.172	0.600
16	2.193	0.0	-2.193	0.0	0.289	0.0	0.0	-0.289	-0.084	3.426	0.640
17	2.516	0.0	-2.516	0.0	0.323	0.0	0.0	-0.323	-0.087	3.700	0.680
18	2.877	0.0	-2.877	0.0	0.361	0.0	0.0	-0.361	-0.090	3.996	0.720
19	3.280	0.0	-3.280	0.0	0.403	0.0	0.0	-0.403	-0.093	4.316	0.760
20	3.729	0.0	-3.729	0.0	0.449	0.0	0.0	-0.449	-0.096	4.661	0.800
21	4.228	0.0	-4.228	0.0	0.500	0.0	0.0	-0.500	-0.099	5.034	0.840
22	4.784	0.0	-4.784	0.0	0.556	0.0	0.0	-0.556	-0.102	5.437	0.880
23	5.402	0.0	-5.402	0.0	0.618	0.0	0.0	-0.618	-0.105	5.871	0.920
24	6.088	0.0	-6.088	0.0	0.686	0.0	0.0	-0.686	-0.108	6.341	0.960
25	6.848	0.0	-6.848	0.0	0.761	0.0	0.0	-0.761	-0.111	6.848	1.000
							TOTAL	-6.848	-1.889		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #2- 4

FINANCING METHOD: PLACE ACCRUALS IN A FUND

TAX ACCOUNTING METHOD: NOT APPLICABLE

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO ESTIMATED DATE OF RETIREMENT.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 0.0 %
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.274	0.0	-0.274	0.0	0.274	0.0	0.0	-0.274	-0.254	1.080	0.254
2	0.569	0.0	-0.569	0.0	0.295	0.0	0.0	-0.295	-0.253	1.166	0.488
3	0.885	0.0	-0.885	0.0	0.317	0.0	0.0	-0.317	-0.251	1.260	0.703
4	1.224	0.0	-1.224	0.0	0.339	0.0	0.0	-0.339	-0.249	1.360	0.900
5	1.585	0.0	-1.585	0.0	0.361	0.0	0.0	-0.361	-0.246	1.469	1.079
6	1.969	0.0	-1.969	0.0	0.384	0.0	0.0	-0.384	-0.242	1.587	1.241
7	2.375	0.0	-2.375	0.0	0.406	0.0	0.0	-0.406	-0.237	1.714	1.386
8	2.803	0.0	-2.803	0.0	0.428	0.0	0.0	-0.428	-0.231	1.851	1.514
9	3.252	0.0	-3.252	0.0	0.449	0.0	0.0	-0.449	-0.225	1.999	1.627
10	3.721	0.0	-3.721	0.0	0.469	0.0	0.0	-0.469	-0.217	2.159	1.723
11	4.207	0.0	-4.207	0.0	0.486	0.0	0.0	-0.486	-0.209	2.332	1.804
12	4.708	0.0	-4.708	0.0	0.501	0.0	0.0	-0.501	-0.199	2.518	1.870
13	5.220	0.0	-5.220	0.0	0.512	0.0	0.0	-0.512	-0.188	2.720	1.920
14	5.739	0.0	-5.739	0.0	0.519	0.0	0.0	-0.519	-0.177	2.937	1.954
15	6.257	0.0	-6.257	0.0	0.518	0.0	0.0	-0.518	-0.163	3.172	1.973
16	6.767	0.0	-6.767	0.0	0.510	0.0	0.0	-0.510	-0.149	3.426	1.975
17	7.257	0.0	-7.257	0.0	0.490	0.0	0.0	-0.490	-0.133	3.700	1.961
18	7.714	0.0	-7.714	0.0	0.457	0.0	0.0	-0.457	-0.114	3.996	1.930
19	8.119	0.0	-8.119	0.0	0.405	0.0	0.0	-0.405	-0.094	4.316	1.881
20	8.449	0.0	-8.449	0.0	0.329	0.0	0.0	-0.329	-0.071	4.661	1.813
21	8.669	0.0	-8.669	0.0	0.221	0.0	0.0	-0.221	-0.044	5.034	1.722
22	8.734	0.0	-8.734	0.0	0.065	0.0	0.0	-0.065	-0.012	5.437	1.607
23	8.572	0.0	-8.572	0.0	-0.163	0.0	0.0	0.163	0.028	5.871	1.460
24	8.053	0.0	-8.053	0.0	-0.519	0.0	0.0	0.519	0.082	6.341	1.270
25	6.848	0.0	-6.848	0.0	-1.204	0.0	0.0	1.204	0.176	6.848	1.000
							TOTAL	-6.848	-3.671		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #2-B3

FINANCING METHOD: PLACE ACCRUALS IN A FUND

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %
TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.022	0.0	-0.022	0.0	0.022	0.022	0.0	-0.043	-0.040	1.080	0.020
2	0.045	0.0	-0.045	0.0	0.023	0.023	0.0	-0.047	-0.040	1.166	0.039
3	0.070	0.0	-0.070	0.0	0.025	0.025	0.0	-0.051	-0.040	1.260	0.056
4	0.098	0.0	-0.098	0.0	0.027	0.027	0.0	-0.055	-0.040	1.360	0.072
5	0.128	0.0	-0.128	0.0	0.030	0.030	0.0	-0.060	-0.041	1.469	0.087
6	0.160	0.0	-0.160	0.0	0.033	0.033	0.0	-0.066	-0.041	1.587	0.101
7	0.196	0.0	-0.196	0.0	0.036	0.036	0.0	-0.072	-0.042	1.714	0.115
8	0.236	0.0	-0.236	0.0	0.040	0.040	0.0	-0.079	-0.043	1.851	0.128
9	0.280	0.0	-0.280	0.0	0.044	0.044	0.0	-0.088	-0.044	1.999	0.140
10	0.328	0.0	-0.328	0.0	0.049	0.049	0.0	-0.097	-0.045	2.159	0.152
11	0.382	0.0	-0.382	0.0	0.054	0.054	0.0	-0.108	-0.046	2.332	0.164
12	0.443	0.0	-0.443	0.0	0.060	0.060	0.0	-0.121	-0.048	2.518	0.176
13	0.511	0.0	-0.511	0.0	0.068	0.068	0.0	-0.136	-0.050	2.720	0.188
14	0.587	0.0	-0.587	0.0	0.076	0.076	0.0	-0.153	-0.052	2.937	0.200
15	0.674	0.0	-0.674	0.0	0.087	0.087	0.0	-0.173	-0.055	3.172	0.212
16	0.772	0.0	-0.772	0.0	0.099	0.099	0.0	-0.197	-0.058	3.426	0.225
17	0.885	0.0	-0.885	0.0	0.113	0.113	0.0	-0.226	-0.061	3.700	0.239
18	1.015	0.0	-1.015	0.0	0.130	0.130	0.0	-0.261	-0.065	3.996	0.254
19	1.167	0.0	-1.167	0.0	0.152	0.152	0.0	-0.303	-0.070	4.316	0.270
20	1.345	0.0	-1.345	0.0	0.178	0.178	0.0	-0.357	-0.077	4.661	0.289
21	1.558	0.0	-1.558	0.0	0.213	0.213	0.0	-0.426	-0.085	5.034	0.310
22	1.817	0.0	-1.817	0.0	0.259	0.259	0.0	-0.518	-0.095	5.437	0.334
23	2.141	0.0	-2.141	0.0	0.324	0.324	0.0	-0.649	-0.111	5.871	0.365
24	2.570	0.0	-2.570	0.0	0.429	0.429	0.0	-0.858	-0.135	6.341	0.405
25	3.219	0.0	-3.219	0.0	0.648	0.648	0.0	-1.296	-0.189	6.848	0.470
							TOTAL	-6.437	-1.613		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #2-84

FINANCING METHOD: PLACE ACCRUALS IN A FUND

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO ESTIMATED DATE OF RETIREMENT.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0			0.137	0.137	0.0	-0.274	-0.254	1.080	0.127
1	0.137	0.0	-0.137	0.0	0.137	0.137	0.0	-0.273	-0.234	1.166	0.234
2	0.273	0.0	-0.273	0.0	0.137	0.137	0.0	-0.272	-0.216	1.260	0.325
3	0.410	0.0	-0.410	0.0	0.136	0.136	0.0	-0.271	-0.199	1.360	0.401
4	0.545	0.0	-0.545	0.0	0.136	0.136	0.0	-0.270	-0.184	1.469	0.463
5	0.680	0.0	-0.680	0.0	0.135	0.135	0.0	-0.269	-0.169	1.587	0.513
6	0.815	0.0	-0.815	0.0	0.134	0.134	0.0	-0.268	-0.156	1.714	0.553
7	0.948	0.0	-0.948	0.0	0.134	0.134	0.0	-0.267	-0.144	1.851	0.584
8	1.082	0.0	-1.082	0.0	0.133	0.133	0.0	-0.265	-0.133	1.999	0.608
9	1.215	0.0	-1.215	0.0	0.133	0.133	0.0	-0.264	-0.122	2.159	0.624
10	1.347	0.0	-1.347	0.0	0.132	0.132	0.0	-0.263	-0.113	2.332	0.634
11	1.478	0.0	-1.478	0.0	0.131	0.131	0.0	-0.261	-0.104	2.518	0.639
12	1.608	0.0	-1.608	0.0	0.131	0.131	0.0	-0.260	-0.095	2.720	0.639
13	1.738	0.0	-1.738	0.0	0.130	0.130	0.0	-0.258	-0.088	2.937	0.636
14	1.867	0.0	-1.867	0.0	0.129	0.129	0.0	-0.256	-0.081	3.172	0.629
15	1.995	0.0	-1.995	0.0	0.128	0.128	0.0	-0.254	-0.074	3.426	0.619
16	2.122	0.0	-2.122	0.0	0.127	0.127	0.0	-0.252	-0.068	3.700	0.608
17	2.248	0.0	-2.248	0.0	0.126	0.126	0.0	-0.249	-0.062	3.996	0.594
18	2.372	0.0	-2.372	0.0	0.125	0.125	0.0	-0.246	-0.057	4.316	0.578
19	2.496	0.0	-2.496	0.0	0.123	0.123	0.0	-0.243	-0.052	4.661	0.561
20	2.617	0.0	-2.617	0.0	0.121	0.121	0.0	-0.239	-0.048	5.034	0.544
21	2.737	0.0	-2.737	0.0	0.120	0.120	0.0	-0.234	-0.043	5.437	0.525
22	2.854	0.0	-2.854	0.0	0.117	0.117	0.0	-0.228	-0.039	5.871	0.505
23	2.968	0.0	-2.968	0.0	0.114	0.114	0.0	-0.219	-0.035	6.341	0.485
24	3.077	0.0	-3.077	0.0	0.109	0.109	0.0	-0.201	-0.029	6.848	0.464
25	3.178	0.0	-3.178	0.0	0.101	0.101	0.0				
							TOTAL	-6.356	-2.799		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #2-C3

FINANCING METHOD: PLACE ACCRUALS IN A FUND

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.043	-0.022	-0.043	0.022	0.043	0.0	0.0	-0.043	-0.040	1.080	0.040
2	0.093	-0.047	-0.093	0.047	0.050	0.001	0.001	-0.052	-0.044	1.166	0.080
3	0.151	-0.076	-0.151	0.076	0.058	0.002	0.002	-0.062	-0.049	1.260	0.120
4	0.218	-0.109	-0.218	0.109	0.067	0.003	0.003	-0.073	-0.053	1.360	0.160
5	0.294	-0.147	-0.294	0.147	0.076	0.004	0.004	-0.085	-0.058	1.469	0.200
6	0.381	-0.190	-0.381	0.190	0.087	0.006	0.006	-0.099	-0.062	1.587	0.240
7	0.480	-0.240	-0.480	0.240	0.099	0.008	0.008	-0.114	-0.067	1.714	0.280
8	0.592	-0.296	-0.592	0.296	0.112	0.010	0.010	-0.132	-0.071	1.851	0.320
9	0.720	-0.360	-0.720	0.360	0.127	0.012	0.012	-0.151	-0.076	1.999	0.360
10	0.864	-0.432	-0.864	0.432	0.144	0.014	0.014	-0.173	-0.080	2.159	0.400
11	1.026	-0.513	-1.026	0.513	0.162	0.017	0.017	-0.197	-0.084	2.332	0.440
12	1.209	-0.604	-1.209	0.604	0.183	0.021	0.021	-0.224	-0.089	2.518	0.480
13	1.414	-0.707	-1.414	0.707	0.205	0.024	0.024	-0.254	-0.093	2.720	0.520
14	1.645	-0.822	-1.645	0.822	0.231	0.028	0.028	-0.287	-0.098	2.937	0.560
15	1.903	-0.952	-1.903	0.952	0.258	0.033	0.033	-0.324	-0.102	3.172	0.600
16	2.193	-1.096	-2.193	1.096	0.289	0.038	0.038	-0.365	-0.107	3.426	0.640
17	2.516	-1.258	-2.516	1.258	0.323	0.044	0.044	-0.411	-0.111	3.700	0.680
18	2.877	-1.439	-2.877	1.439	0.361	0.050	0.050	-0.462	-0.116	3.996	0.720
19	3.280	-1.640	-3.280	1.640	0.403	0.058	0.058	-0.518	-0.120	4.316	0.760
20	3.729	-1.864	-3.729	1.864	0.449	0.066	0.066	-0.580	-0.124	4.661	0.800
21	4.228	-2.114	-4.228	2.114	0.500	0.075	0.075	-0.649	-0.129	5.034	0.840
22	4.784	-2.392	-4.784	2.392	0.556	0.085	0.085	-0.725	-0.133	5.437	0.880
23	5.402	-2.701	-5.402	2.701	0.618	0.096	0.096	-0.809	-0.138	5.871	0.920
24	6.088	-3.044	-6.088	3.044	0.686	0.108	0.108	-0.902	-0.142	6.341	0.960
25	6.848	-3.424	-6.848	3.424	0.761	0.122	0.122	-1.004	-0.147	6.848	1.000
							TOTAL	-8.694	-2.333		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #2-C4

FINANCING METHOD: PLACE ACCRUALS IN A FUND

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO ESTIMATED DATE OF RETIREMENT.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%
ON FUND: 0.0 %

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%
FUND GROWTH: 0.0 %
RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.274	-0.137	-0.274	0.137	0.274	0.0	0.0	-0.274	-0.254	1.080	0.254
2	0.569	-0.284	-0.569	0.284	0.295	0.005	0.005	-0.306	-0.262	1.166	0.488
3	0.885	-0.443	-0.885	0.443	0.317	0.011	0.011	-0.339	-0.269	1.260	0.703
4	1.224	-0.612	-1.224	0.612	0.339	0.018	0.018	-0.374	-0.275	1.360	0.900
5	1.585	-0.793	-1.585	0.793	0.361	0.024	0.024	-0.410	-0.279	1.469	1.079
6	1.969	-0.984	-1.969	0.984	0.384	0.032	0.032	-0.447	-0.282	1.587	1.241
7	2.375	-1.187	-2.375	1.187	0.406	0.039	0.039	-0.485	-0.283	1.714	1.386
8	2.803	-1.401	-2.803	1.401	0.428	0.047	0.047	-0.523	-0.283	1.851	1.514
9	3.252	-1.626	-3.252	1.626	0.449	0.056	0.056	-0.561	-0.281	1.999	1.627
10	3.721	-1.860	-3.721	1.860	0.469	0.065	0.065	-0.599	-0.277	2.159	1.723
11	4.207	-2.103	-4.207	2.103	0.486	0.074	0.074	-0.635	-0.272	2.332	1.804
12	4.708	-2.354	-4.708	2.354	0.501	0.084	0.084	-0.669	-0.266	2.518	1.870
13	5.220	-2.610	-5.220	2.610	0.512	0.094	0.094	-0.701	-0.258	2.720	1.920
14	5.739	-2.869	-5.739	2.869	0.519	0.104	0.104	-0.727	-0.248	2.937	1.954
15	6.257	-3.129	-6.257	3.129	0.518	0.115	0.115	-0.748	-0.236	3.172	1.973
16	6.767	-3.383	-6.767	3.383	0.510	0.125	0.125	-0.760	-0.222	3.426	1.975
17	7.257	-3.629	-7.257	3.629	0.490	0.135	0.135	-0.761	-0.206	3.700	1.961
18	7.714	-3.857	-7.714	3.857	0.457	0.145	0.145	-0.747	-0.187	3.996	1.930
19	8.119	-4.060	-8.119	4.060	0.405	0.154	0.154	-0.714	-0.165	4.316	1.881
20	8.449	-4.224	-8.449	4.224	0.329	0.162	0.162	-0.654	-0.140	4.661	1.813
21	8.669	-4.335	-8.669	4.335	0.221	0.169	0.169	-0.559	-0.111	5.034	1.722
22	8.734	-4.367	-8.734	4.367	0.065	0.173	0.173	-0.412	-0.076	5.437	1.607
23	8.572	-4.286	-8.572	4.286	-0.163	0.175	0.175	-0.187	-0.032	5.871	1.460
24	8.053	-4.026	-8.053	4.026	-0.519	0.171	0.171	0.176	0.028	6.341	1.270
25	6.848	-3.424	-6.848	3.424	-1.204	0.161	0.161	0.882	0.129	6.848	1.000
							TOTAL	-11.533	-5.006		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #3- 3

FINANCING METHOD: FINANCE AT DECOMMISSIONING

TAX ACCOUNTING METHOD: NOT APPLICABLE

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 0.0 %

RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.0	0.043	-0.043	0.0	0.043	0.0	0.0	-0.043	-0.040	1.080	0.040
2	0.0	0.093	-0.093	0.0	0.050	-0.002	-0.002	-0.047	-0.040	1.166	0.080
3	0.0	0.151	-0.151	0.0	0.058	-0.004	-0.004	-0.050	-0.040	1.260	0.120
4	0.0	0.218	-0.218	0.0	0.067	-0.006	-0.006	-0.054	-0.040	1.360	0.160
5	0.0	0.294	-0.294	0.0	0.076	-0.009	-0.009	-0.059	-0.040	1.469	0.200
6	0.0	0.381	-0.381	0.0	0.087	-0.012	-0.012	-0.063	-0.040	1.587	0.240
7	0.0	0.480	-0.480	0.0	0.099	-0.015	-0.015	-0.069	-0.040	1.714	0.280
8	0.0	0.592	-0.592	0.0	0.112	-0.019	-0.019	-0.074	-0.040	1.851	0.320
9	0.0	0.720	-0.720	0.0	0.127	-0.024	-0.024	-0.080	-0.040	1.999	0.360
10	0.0	0.864	-0.864	0.0	0.144	-0.029	-0.029	-0.086	-0.040	2.159	0.400
11	0.0	1.026	-1.026	0.0	0.162	-0.035	-0.035	-0.093	-0.040	2.332	0.440
12	0.0	1.209	-1.209	0.0	0.183	-0.041	-0.041	-0.101	-0.040	2.518	0.480
13	0.0	1.414	-1.414	0.0	0.205	-0.048	-0.048	-0.109	-0.040	2.720	0.520
14	0.0	1.645	-1.645	0.0	0.231	-0.057	-0.057	-0.117	-0.040	2.937	0.560
15	0.0	1.903	-1.903	0.0	0.258	-0.066	-0.066	-0.127	-0.040	3.172	0.600
16	0.0	2.193	-2.193	0.0	0.289	-0.076	-0.076	-0.137	-0.040	3.426	0.640
17	0.0	2.516	-2.516	0.0	0.323	-0.088	-0.088	-0.148	-0.040	3.700	0.680
18	0.0	2.877	-2.877	0.0	0.361	-0.101	-0.101	-0.160	-0.040	3.996	0.720
19	0.0	3.280	-3.280	0.0	0.403	-0.115	-0.115	-0.173	-0.040	4.316	0.760
20	0.0	3.729	-3.729	0.0	0.449	-0.131	-0.131	-0.186	-0.040	4.661	0.800
21	0.0	4.228	-4.228	0.0	0.500	-0.149	-0.149	-0.201	-0.040	5.034	0.840
22	0.0	4.784	-4.784	0.0	0.556	-0.169	-0.169	-0.217	-0.040	5.437	0.880
23	0.0	5.402	-5.402	0.0	0.618	-0.191	-0.191	-0.235	-0.040	5.871	0.920
24	0.0	6.088	-6.088	0.0	0.686	-0.216	-0.216	-0.254	-0.040	6.341	0.960
25	0.0	6.848	-6.848	0.0	0.761	-0.244	-0.244	-0.274	-0.040	6.848	1.000
							TOTAL	-3.158	-1.000		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #3- 4

FINANCING METHOD: FINANCE AT DECOMMISSIONING

TAX ACCOUNTING METHOD: NOT APPLICABLE

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO ESTIMATED DATE OF RETIREMENT.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 0.0 %

RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0			0.274	0.0	0.0	-0.274	-0.254	1.080	0.254
1	0.0	0.274	-0.274	0.0	0.295	-0.011	-0.011	-0.273	-0.234	1.166	0.488
2	0.0	0.569	-0.569	0.0	0.317	-0.023	-0.023	-0.271	-0.215	1.260	0.703
3	0.0	0.885	-0.885	0.0	0.339	-0.035	-0.035	-0.268	-0.197	1.360	0.900
4	0.0	1.224	-1.224	0.0	0.361	-0.049	-0.049	-0.263	-0.179	1.469	1.079
5	0.0	1.585	-1.585	0.0	0.384	-0.063	-0.063	-0.257	-0.162	1.587	1.241
6	0.0	1.969	-1.969	0.0	0.406	-0.079	-0.079	-0.249	-0.145	1.714	1.386
7	0.0	2.375	-2.375	0.0	0.428	-0.095	-0.095	-0.238	-0.129	1.851	1.514
8	0.0	2.803	-2.803	0.0	0.449	-0.112	-0.112	-0.225	-0.112	1.999	1.627
9	0.0	3.252	-3.252	0.0	0.469	-0.130	-0.130	-0.209	-0.097	2.159	1.723
10	0.0	3.721	-3.721	0.0	0.486	-0.149	-0.149	-0.189	-0.081	2.332	1.804
11	0.0	4.207	-4.207	0.0	0.501	-0.168	-0.168	-0.165	-0.065	2.518	1.870
12	0.0	4.708	-4.708	0.0	0.512	-0.188	-0.188	-0.136	-0.050	2.720	1.920
13	0.0	5.220	-5.220	0.0	0.519	-0.209	-0.209	-0.101	-0.034	2.937	1.954
14	0.0	5.739	-5.739	0.0	0.518	-0.230	-0.230	-0.059	-0.019	3.172	1.973
15	0.0	6.257	-6.257	0.0	0.510	-0.250	-0.250	-0.009	-0.003	3.426	1.975
16	0.0	6.767	-6.767	0.0	0.490	-0.271	-0.271	0.051	0.014	3.700	1.961
17	0.0	7.257	-7.257	0.0	0.457	-0.290	-0.290	0.124	0.031	3.996	1.930
18	0.0	7.714	-7.714	0.0	0.405	-0.309	-0.309	0.212	0.049	4.316	1.881
19	0.0	8.119	-8.119	0.0	0.329	-0.325	-0.325	0.320	0.069	4.661	1.813
20	0.0	8.449	-8.449	0.0	0.221	-0.338	-0.338	0.455	0.090	5.034	1.722
21	0.0	8.669	-8.669	0.0	0.065	-0.347	-0.347	0.629	0.116	5.437	1.607
22	0.0	8.734	-8.734	0.0	-0.163	-0.349	-0.349	0.862	0.147	5.871	1.460
23	0.0	8.572	-8.572	0.0	-0.519	-0.343	-0.343	1.204	0.190	6.341	1.270
24	0.0	8.053	-8.053	0.0	-1.204	-0.322	-0.322	1.849	0.270	6.848	1.000
25	0.0	6.848	-6.848	0.0							
							TOTAL	2.521	-1.000		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #3-B3

FINANCING METHOD: FINANCE AT DECOMMISSIONING — RATE OF RETURN ON CAPITAL: 4.00%

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 8.00%

RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.0	0.022	-0.022	0.0	0.022	0.022	0.0	-0.043	-0.040	1.080	0.020
2	0.0	0.045	-0.045	0.0	0.023	0.022	-0.001	-0.045	-0.039	1.166	0.039
3	0.0	0.070	-0.070	0.0	0.025	0.023	-0.002	-0.047	-0.037	1.260	0.056
4	0.0	0.098	-0.098	0.0	0.027	0.025	-0.003	-0.049	-0.036	1.360	0.072
5	0.0	0.128	-0.128	0.0	0.030	0.026	-0.004	-0.052	-0.035	1.469	0.087
6	0.0	0.160	-0.160	0.0	0.033	0.028	-0.005	-0.055	-0.035	1.587	0.101
7	0.0	0.196	-0.196	0.0	0.036	0.030	-0.006	-0.059	-0.035	1.714	0.115
8	0.0	0.236	-0.236	0.0	0.040	0.032	-0.008	-0.064	-0.034	1.851	0.128
9	0.0	0.280	-0.280	0.0	0.044	0.034	-0.009	-0.069	-0.034	1.999	0.140
10	0.0	0.328	-0.328	0.0	0.049	0.037	-0.011	-0.075	-0.035	2.159	0.152
11	0.0	0.382	-0.382	0.0	0.054	0.041	-0.013	-0.082	-0.035	2.332	0.164
12	0.0	0.443	-0.443	0.0	0.060	0.045	-0.015	-0.090	-0.036	2.518	0.176
13	0.0	0.511	-0.511	0.0	0.068	0.050	-0.018	-0.100	-0.037	2.720	0.188
14	0.0	0.587	-0.587	0.0	0.076	0.056	-0.020	-0.112	-0.038	2.937	0.200
15	0.0	0.674	-0.674	0.0	0.087	0.063	-0.023	-0.126	-0.040	3.172	0.212
16	0.0	0.772	-0.772	0.0	0.099	0.072	-0.027	-0.143	-0.042	3.426	0.225
17	0.0	0.885	-0.885	0.0	0.113	0.082	-0.031	-0.164	-0.044	3.700	0.239
18	0.0	1.015	-1.015	0.0	0.130	0.095	-0.035	-0.190	-0.047	3.996	0.254
19	0.0	1.167	-1.167	0.0	0.152	0.111	-0.041	-0.222	-0.051	4.316	0.270
20	0.0	1.345	-1.345	0.0	0.178	0.132	-0.047	-0.263	-0.057	4.661	0.289
21	0.0	1.558	-1.558	0.0	0.213	0.159	-0.054	-0.318	-0.063	5.034	0.310
22	0.0	1.817	-1.817	0.0	0.259	0.197	-0.062	-0.393	-0.072	5.437	0.334
23	0.0	2.141	-2.141	0.0	0.324	0.252	-0.073	-0.504	-0.086	5.871	0.365
24	0.0	2.570	-2.570	0.0	0.429	0.343	-0.086	-0.687	-0.108	6.341	0.405
25	0.0	3.219	-3.219	0.0	0.648	0.545	-0.103	-1.091	-0.159	6.848	0.470
							TOTAL	-5.043	-1.276		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #3-B4

FINANCING METHOD: FINANCE AT DECOMMISSIONING

TAX ACCOUNTING METHOD: DEPRECIATION RESERVE ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO ESTIMATED DATE OF RETIREMENT.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%

RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.0	0.137	-0.137	0.0	0.137	0.137	0.0	-0.274	-0.254	1.080	0.127
2	0.0	0.273	-0.273	0.0	0.137	0.131	-0.005	-0.262	-0.225	1.166	0.234
3	0.0	0.410	-0.410	0.0	0.136	0.125	-0.011	-0.250	-0.199	1.260	0.325
4	0.0	0.545	-0.545	0.0	0.136	0.119	-0.016	-0.238	-0.175	1.360	0.401
5	0.0	0.680	-0.680	0.0	0.135	0.113	-0.022	-0.226	-0.154	1.469	0.463
6	0.0	0.815	-0.815	0.0	0.134	0.107	-0.027	-0.215	-0.135	1.587	0.513
7	0.0	0.948	-0.948	0.0	0.134	0.101	-0.033	-0.203	-0.118	1.714	0.553
8	0.0	1.082	-1.082	0.0	0.133	0.095	-0.038	-0.191	-0.103	1.851	0.584
9	0.0	1.215	-1.215	0.0	0.133	0.089	-0.043	-0.179	-0.089	1.999	0.608
10	0.0	1.347	-1.347	0.0	0.132	0.083	-0.049	-0.167	-0.077	2.159	0.624
11	0.0	1.478	-1.478	0.0	0.131	0.077	-0.054	-0.155	-0.066	2.332	0.634
12	0.0	1.608	-1.608	0.0	0.131	0.071	-0.059	-0.143	-0.057	2.518	0.639
13	0.0	1.738	-1.738	0.0	0.130	0.065	-0.064	-0.131	-0.048	2.720	0.639
14	0.0	1.867	-1.867	0.0	0.129	0.059	-0.070	-0.119	-0.040	2.937	0.636
15	0.0	1.995	-1.995	0.0	0.128	0.053	-0.075	-0.107	-0.034	3.172	0.629
16	0.0	2.122	-2.122	0.0	0.127	0.047	-0.080	-0.094	-0.028	3.426	0.619
17	0.0	2.248	-2.248	0.0	0.126	0.041	-0.085	-0.082	-0.022	3.700	0.608
18	0.0	2.372	-2.372	0.0	0.125	0.035	-0.090	-0.069	-0.017	3.996	0.594
19	0.0	2.496	-2.496	0.0	0.123	0.028	-0.095	-0.056	-0.013	4.316	0.578
20	0.0	2.617	-2.617	0.0	0.121	0.022	-0.100	-0.043	-0.009	4.661	0.561
21	0.0	2.737	-2.737	0.0	0.120	0.015	-0.105	-0.030	-0.006	5.034	0.544
22	0.0	2.854	-2.854	0.0	0.117	0.008	-0.109	-0.015	-0.003	5.437	0.525
23	0.0	2.968	-2.968	0.0	0.114	-0.000	-0.114	0.000	0.000	5.871	0.505
24	0.0	3.077	-3.077	0.0	0.109	-0.009	-0.119	0.018	0.003	6.341	0.485
25	0.0	3.178	-3.178	0.0	0.101	-0.022	-0.123	0.045	0.007	6.848	0.464
							TOTAL	-3.186	-1.864		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #3-C3

FINANCING METHOD: FINANCE AT DECOMMISSIONING

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO THE END OF EACH ACCOUNTING YEAR.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%

RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0									
1	0.0	0.022	-0.043	0.022	0.043	0.0	0.0	-0.043	-0.040	1.080	0.040
2	0.0	0.047	-0.093	0.047	0.050	-0.001	-0.001	-0.048	-0.041	1.166	0.080
3	0.0	0.076	-0.151	0.076	0.058	-0.002	-0.002	-0.054	-0.043	1.260	0.120
4	0.0	0.109	-0.218	0.109	0.067	-0.003	-0.003	-0.060	-0.044	1.360	0.160
5	0.0	0.147	-0.294	0.147	0.076	-0.004	-0.004	-0.067	-0.046	1.469	0.200
6	0.0	0.190	-0.381	0.190	0.087	-0.006	-0.006	-0.075	-0.047	1.587	0.240
7	0.0	0.240	-0.480	0.240	0.099	-0.008	-0.008	-0.084	-0.049	1.714	0.280
8	0.0	0.296	-0.592	0.296	0.112	-0.010	-0.010	-0.093	-0.050	1.851	0.320
9	0.0	0.360	-0.720	0.360	0.127	-0.012	-0.012	-0.104	-0.052	1.999	0.360
10	0.0	0.432	-0.864	0.432	0.144	-0.014	-0.014	-0.115	-0.053	2.159	0.400
11	0.0	0.513	-1.026	0.513	0.162	-0.017	-0.017	-0.128	-0.055	2.332	0.440
12	0.0	0.604	-1.209	0.604	0.183	-0.021	-0.021	-0.142	-0.056	2.518	0.480
13	0.0	0.707	-1.414	0.707	0.205	-0.024	-0.024	-0.157	-0.058	2.720	0.520
14	0.0	0.822	-1.645	0.822	0.231	-0.028	-0.028	-0.174	-0.059	2.937	0.560
15	0.0	0.952	-1.903	0.952	0.258	-0.033	-0.033	-0.193	-0.061	3.172	0.600
16	0.0	1.096	-2.193	1.096	0.289	-0.038	-0.038	-0.213	-0.062	3.426	0.640
17	0.0	1.258	-2.516	1.258	0.323	-0.044	-0.044	-0.236	-0.064	3.700	0.680
18	0.0	1.439	-2.877	1.439	0.361	-0.050	-0.050	-0.260	-0.065	3.996	0.720
19	0.0	1.640	-3.280	1.640	0.403	-0.058	-0.058	-0.288	-0.067	4.316	0.760
20	0.0	1.864	-3.729	1.864	0.449	-0.066	-0.066	-0.318	-0.068	4.661	0.800
21	0.0	2.114	-4.228	2.114	0.500	-0.075	-0.075	-0.351	-0.070	5.034	0.840
22	0.0	2.392	-4.784	2.392	0.556	-0.085	-0.085	-0.387	-0.071	5.437	0.880
23	0.0	2.701	-5.402	2.701	0.618	-0.096	-0.096	-0.426	-0.073	5.871	0.920
24	0.0	3.044	-6.088	3.044	0.686	-0.108	-0.108	-0.470	-0.074	6.341	0.960
25	0.0	3.424	-6.848	3.424	0.761	-0.122	-0.122	-0.517	-0.076	6.848	1.000
							TOTAL	-5.003	-1.444		

ANALYSIS OF DECOMMISSIONING FINANCING AND ACCOUNTING ALTERNATIVES

CASE #3-C4

FINANCING METHOD: FINANCE AT DECOMMISSIONING

TAX ACCOUNTING METHOD: DEFERRED TAX ACCOUNTING

DECOMMISSIONING COST ESTIMATE PROJECTED AT ASSUMED
RATE OF INFLATION TO ESTIMATED DATE OF RETIREMENT.
ASSUMED RATE OF INFLATION: 8.00%

RATE OF RETURN ON CAPITAL: 4.00%

TAX RATES:
RETURN ON CAPITAL: 50.00%
AMORTIZATION EXPENSE: 50.00%

RESERVE COMPOUNDED AT 8.00%

	BALANCE SHEET ACCOUNTS				INCOME ACCOUNTS						
AGE	FUND	CAPITAL	RESERVE	DEF. TAXES	AMORT EXPENSE	TAX EXPENSE	RETURN	REVENUE	CONST $ REVENUE	PR LEVEL COST	RATIO
0	0.0	0.0			0.274	0.0	0.0	-0.274	-0.254	1.080	0.254
1	0.0	0.137	-0.274	0.137	0.295	-0.005	-0.005	-0.284	-0.243	1.166	0.488
2	0.0	0.284	-0.569	0.284	0.317	-0.011	-0.011	-0.294	-0.233	1.260	0.703
3	0.0	0.443	-0.885	0.443	0.339	-0.018	-0.018	-0.303	-0.223	1.360	0.900
4	0.0	0.612	-1.224	0.612	0.361	-0.024	-0.024	-0.312	-0.212	1.469	1.079
5	0.0	0.793	-1.585	0.793	0.384	-0.032	-0.032	-0.320	-0.202	1.587	1.241
6	0.0	0.984	-1.969	0.984	0.406	-0.039	-0.039	-0.327	-0.191	1.714	1.386
7	0.0	1.187	-2.375	1.187	0.428	-0.047	-0.047	-0.333	-0.180	1.851	1.514
8	0.0	1.401	-2.803	1.401	0.449	-0.056	-0.056	-0.337	-0.169	1.999	1.627
9	0.0	1.626	-3.252	1.626	0.469	-0.065	-0.065	-0.339	-0.157	2.159	1.723
10	0.0	1.860	-3.721	1.860	0.486	-0.074	-0.074	-0.338	-0.145	2.332	1.804
11	0.0	2.103	-4.207	2.103	0.501	-0.084	-0.084	-0.333	-0.132	2.518	1.870
12	0.0	2.354	-4.708	2.354	0.512	-0.094	-0.094	-0.324	-0.119	2.720	1.920
13	0.0	2.610	-5.220	2.610	0.519	-0.104	-0.104	-0.310	-0.105	2.937	1.954
14	0.0	2.869	-5.739	2.869	0.518	-0.115	-0.115	-0.289	-0.091	3.172	1.973
15	0.0	3.129	-6.257	3.129	0.510	-0.125	-0.125	-0.259	-0.076	3.426	1.975
16	0.0	3.383	-6.767	3.383	0.490	-0.135	-0.135	-0.220	-0.059	3.700	1.961
17	0.0	3.629	-7.257	3.629	0.457	-0.145	-0.145	-0.167	-0.042	3.996	1.930
18	0.0	3.857	-7.714	3.857	0.405	-0.154	-0.154	-0.097	-0.022	4.316	1.881
19	0.0	4.060	-8.119	4.060	0.329	-0.162	-0.162	-0.005	-0.001	4.661	1.813
20	0.0	4.224	-8.449	4.224	0.221	-0.169	-0.169	0.117	0.023	5.034	1.722
21	0.0	4.335	-8.669	4.335	0.065	-0.173	-0.173	0.282	0.052	5.437	1.607
22	0.0	4.367	-8.734	4.367	-0.163	-0.175	-0.175	0.512	0.087	5.871	1.460
23	0.0	4.286	-8.572	4.286	-0.519	-0.171	-0.171	0.862	0.136	6.341	1.270
24	0.0	4.026	-8.053	4.026	-1.204	-0.161	-0.161	1.527	0.223	6.848	1.000
25	0.0	3.424	-6.848	3.424							
							TOTAL	-2.164	-2.335		

POWER REACTOR DECOMMISSIONING:
NRC REGULATORY DEVELOPMENTS

Nicholas S. Reynolds
Partner
Debevoise & Liberman

The following comments represent my personal views on the legal and financial aspects of power reactor decommissioning, and not the views of the Utility Decommissioning Group (to which I am Legal Counsel). Before I discuss these aspects of the decommissioning question, let me first provide a little background on the Utility Decommissioning Group. The Group was formed in late 1977 to participate in the NRC reevaluation of its policies and regulations governing decommissioning. Since that time, the Group has followed closely and provided input to the development of the legal, financial and technical aspects of power reactor decommissioning by the NRC. The Group consists of 15 power reactor licensees and the Edison Electric Institute.

I. NRC ROLE IN DECOMMISSIONING FINANCING

In my view, the NRC lacks jurisdiction or authority over matters of economic regulation and utility financing which would be necessary to impose a particular decommissioning funding arrangement on NRC power reactor licensees. Such matters are properly addressed by State ratemaking agencies or the Federal Energy Regulatory Commission ("FERC").

The jurisdiction of the States and FERC is specifically preserved in Section 271 of the Atomic Energy Act, which provides that nothing in the Act affects "the authority or regulations of any Federal, State or local agency with respect to the generation, sale or transmission of electric power produced through the use of nuclear facilities." In addition, Section 272 of the Act subjects NRC licensees which either transmit or sell at wholesale in interstate commerce electric energy generated by nuclear power reactors to the regulatory provisions of the Federal Power Act.

The NRC Staff apparently does not dispute that it lacks jurisdiction to prescribe the funding arrangement for decommissioning cost recovery. For example, in the Staff's draft report titled "Assuring the Availability of Funds for Decommissioning Nuclear Facilities" (NUREG-0584, Rev. 1), the Staff noted that "NRC should avoid imposing requirements so specific that they impinge on state or federal ratemaking authority or on utility accounting practices, particularly when the effects of those requirements are not all that clear" (NUREG-0584, at p. 38). Likewise, the Staff observed at the State workshop last year in Seattle that the NRC "is not in the ratemaking business and does not want to [be]," and that the NRC could not "preempt other authorities" in the realm of economic regulation (NUREG/CP-0008, at p. 242). Thus, it appears that all parties to the decommissioning question -- the NRC, the regulated industry, and

State and Federal economic regulators -- are in agreement that the NRC should not and as a matter of law may not involve itself in matters of economic regulation.

What then is the proper formal role for the NRC on the legal and financial aspects of the decommissioning question. The NRC has jurisdiction and authority to require a licensee to demonstrate that it possesses or has reasonable assurance of obtaining the funds necessary to cover, inter alia, the estimated costs of permanently shutting down the facility and maintaining it in a safe condition. These regulations are founded in § 182 of the Atomic Energy Act, which provides for a determination by the NRC that an applicant is financially qualified to perform the activities contemplated by the license. NRC regulations require an applicant for a power reactor operating license to demonstrate that it is financially qualified to decommission the reactor under review. 10 C.F.R. Part 50, §50.33(f) and Appendix C.

Typically the NRC Staff review on the issue of financial qualifications to decommission a reactor has not been of major significance. The Staff in the past generally has been content to make the necessary findings of financial qualifications on the basis of annual reports, general financial statements, and other general information required to be submitted in the OL application. However, I sense an indication that the Staff in its proposals to the Commission on the decommissioning rulemaking will recommend that a much more serious financial qualifications review be mandated on the decommissioning question.

In addition, the NRC could have an important advisory role to play in providing its licensees and the States and FERC with guidance as to what the NRC perceives to be a range of acceptable methods to finance decommissioning. In other words, the NRC might indicate the range of methods of decommissioning cost recovery which would generally provide it with the "reasonable assurance" it must have that licensees are financially qualified to decommission. However, the NRC should not preclude any viable funding option from being implemented by the economic regulators. This view is not incompatible with the Commission's statutory need to review for financial qualifications, for if the applicant cannot demonstrate its financial qualifications to the Commission's satisfaction, the Commission may refuse to issue a license. Thus, the Commission could review each application on a case-by-case basis to assure that one of the acceptable funding methods will be utilized, or find as in the alternative that some other arrangement was acceptable.

In addition, the Commission can greatly aid the economic regulators by providing detailed generic analyses of the technology and costs of power reactor decommissioning. These regulators have apparently experienced considerable difficulty in deriving decommissioning cost estimates for use in rate proceedings, and the Commission could fill the void which apparently exists. The NRC Staff issued such reports on PWR decommissioning in June 1978 and

August 1979. It will issue its report on BWR decommissioning shortly.

II. NRC STAFF EVALUATION OF FUNDING OPTIONS

The NRC Staff has developed five criteria with which to evaluate the viability of the various decommissioning funding options. Those criteria are (1) the degree of assurance the option provides that necessary funds will be available when needed; (2) the direct and indirect costs of the option; (3) the equitable aspects of the option (i.e., who pays); (4) the degree of responsiveness of the option to changes in inflation, interest rates, reactor life, and decommissioning costs; and (5) the ability of the option to accommodate differing ownership and jurisdictional arrangements for a given reactor facility.

Against these criteria, the Staff has seriously evaluated the following four basic options for funding decommissioning costs: (1) prepayment or funding at commissioning, (2) a funded reserve accumulated over plant life, (3) negative net salvage depreciation and reinvestment in plant, and (4) surety bonds. In the Staff's draft report on this matter, the Staff indicated a strong preference for the prepayment option, primarily on the bases of the "high level of assurance of funds availability" and the Staff's tentative conclusion that the cost of this option is not substantially higher than other options (NUREG-0584, at p. 39).

I take issue with this tentative conclusion of the Staff on two principal bases. First, the required level of assurance to be provided by a funding option from the standpoint of the Staff must be more clearly defined. The Staff states the question as follows:

> "How high is the probability that the [funding] alternative will actually provide funds when needed to pay for decommissioning?" (NUREG-0584, at p. 5.)

In my view, the essential task for the Staff should not be to identify which option provides the highest degree of assurance, but to determine the range of options which provide reasonable assurance that decommissioning funds will be available when needed. This "reasonable assurance" goal simply is not recognized in the Staff's analysis of the funding options under the assurance criterion, even though the Staff actually correctly identifies it in the conclusion of the report, where it states that:

> "[T]he NRC should allow a wide latitude of approaches to implement some standard level of assurance.
>
> * * *

The NRC's function should be to require assurance of the availability of decommissioning funds within reasonable bounds of cost-effectiveness." [NUREG-0584, at p. 38 (emphasis added).]

Since the Staff's analysis is tainted by the ranking of funding options on a "relative assurance" basis, options which may indeed provide "reasonable assurance" of fund availability were apparently downgraded or precluded by the Staff. In my view the Staff's approach misconstrues pertinent statutory authority and judicial precedent. The Commission has long recognized the appropriateness of the "reasonable assurance" standard in making health and safety determinations, including those as to the financial qualifications of applicants. Likewise, the Courts have found the standard to be consistent with the requirements of the Atomic Energy Act and have affirmed the Commission's use of it as "a valid exercise of the rule-making power conferred upon [the Commission] by statute." Power Reactor Development Co. v. Electrical Workers, 367 U.S. 396, 407 (1961); accord, New England Coalition v. NRC, 582 F.2d 87, 93 (1st Cir. 1978); Nader v. NRC, 513 F.2d 1045, 1052 (D.C. Cir. 1975).

Since the "reasonable assurance" standard clearly reflects the requirements of the Act as interpreted by the Commission and the Courts, it must be followed as the applicable standard in the evaluation of decommissioning funding options. I believe that the Staff's failure to utilize this correct standard in NUREG-0584 is inconsistent with these legal precedents, and therefore unlawfully influences the Staff's tentative conclusions.

The second point on which I take issue with the Staff is its assessment of the relative costs of the various funding options. In my view, NUREG-0584 does not correctly assess the relative costs of each funding option from the viewpoint and in the terms of those who will allocate those costs, viz., State regulators and FERC.

Practical realities of the regulatory system demand that decisions be based on an analysis of costs to consumers and the revenue requirements of the utility. In this latter regard, the costs which are relevant are not the actual engineering and disposal costs of the decommissioning activities, but rather the amounts which the licensee must recover from its ratepayers which, after taxes and other considerations, will yield the actual costs of the activity. The draft report of the Staff fails to account adequately for these facts.

When evaluating the various funding options, one must also consider who will pay the decommissioning costs and at what stages of reactor operation. The Staff recognizes that the prepayment option would most likely necessitate "relatively greater costs on users early in a facility's life or even prior to plant start-up, depending on how and whether the fund is capitalized"

(NUREG-0584, at p. 26). And yet the Staff dismissed the importance of this fact by suggesting that "[a]s a group, the customers at the end [of operation] will be the same as at the beginning." (NUREG-0584, at p. 27). This view is incompatible with the equity criterion established by the Staff, and with the unanimous views of the State representatives at the decommissioning workshop that no group of consumers at a given time during the life of the power reactor should bear a disproportionate share of decommissioning costs. Thus, it is highly doubtful that State regulators or FERC would accept a decommissioning funding scheme which required disproportionate shares from customers during one period of reactor operation compared to other periods.

Of course, NUREG-0584 was merely a <u>draft</u> report published by the NRC Staff to stimulate thinking and comment on these issues. To its credit, the Staff has continued to evaluate the issues raised by NUREG-0584, and is developing a final report on these aspects which is scheduled for issuance in July of this year. We are of course anxious to see how the Staff will now address these complex issues.

The Staff has continued to evaluate the relative costs of various funding options, focussing on the prepayment option and the negative net salvage depreciation option. This latter option is preferred by most NRC licensees and ratemaking authorities. In addition, the Staff has contracted with the New England Conference of Public Utility Commissioners to study these issues. I understand that this report will be issued soon, and that it will conclude that the prepayment option is significantly more costly than the depreciation option, perhaps by as much as a factor of three. This conclusion would confirm the results of studies performed by the Utility Decommissioning Group.

In addition, I hope that the NRC Staff has kept an open mind on the other issues which will contribute to the final Staff recommendation on the financial aspects of decommissioning. In my view, the Staff must recognize the need to preserve flexibility in any decommissioning regulations to be promulgated in order to (1) accommodate the fact that economic regulators will ultimately decide the method of decommissioning cost recovery, (2) recognize that any funding option which provides "reasonable assurance" that the funds will be available when necessary should be acceptable, and (3) recognize that NRC licensees consist not only of investor-owned utilities, but State and federal agencies, municipals, rural electric cooperatives, and public utility districts.

The NRC must not promulgate any regulation which might preclude or otherwise hinder or fail to account for the range of different financing capabilities of and limitations on various NRC licensees. Again, this suggests a need for the maintenance of a high degree of flexibility in the decommissioning regulation to ensure that no licensee is precluded from using perhaps the only funding mechanism which is consistent with its ownership obligations and economic structure.

This is not to say, however, that the NRC Staff has not recognized the need to consider that some power reactors are owned by various entities (public and private), sometimes jointly, and that such relationships may raise additional considerations. NUREG-0584 recognizes the need to study these jurisdictional problems in greater detail (NUREG-0584, at p. 30), and I understand that the report by the New England Conference will address these problems. Without having seen the New England Conference report or discussed these jurisdictional problems with the NRC Staff in any detail, I suspect that the complexity and diversity of the problems compel only one reasonable conclusion -- that the Staff must evaluate the financial qualifications of reactor owners to decommission on a case-by-case basis, where matters of joint ownership, multi-jurisdictions, and various funding options can be evaluated specifically.

III. ROUTINE DECOMMISSIONING v. PREMATURE DECOMMISSIONING

Thus, in my view, the financial aspects of routine decommissioning are straightforward. In general, the NRC should permit power reactor licenses to meet the "reasonable assurance" test for financial qualifications through any of several funding options which provide the Commission with the necessary confidence level. This determination should be made by the Commission on a case-by-case basis, considering the projected mode and costs of decommissioning, the projected timeframe for decommissioning, the organizational structure of the licensee, and the system size and strength of the licensee. For many NRC licensees, the financial qualifications determination might be made without reference or commitment to any decommissioning funding method. The implication here is that these licensees are such viable entities that decommissioning costs can be financed routinely and without undue burden.

This treatment is consistent, in my opinion, with the conclusion that there is a high level of assurance that electric utilities will remain economically viable through the distant future. An examination of the framework for the economic regulation for investor-owned utilities, when viewed together with the absolute necessity of the product (electricity) marketed by the industry, demonstrates that there is a high level of assurance that electric utilities will remain healthy.

The Government-authorized monopoly of utilities has traditionally been coupled with careful regulation of the industry. Economic regulation of investor-owned electric utilities is performed by State utility commissions and FERC. It is well-settled that in exercising their regulatory functions, utility commissions must establish rates which permit the supplier of electrical services to receive a "reasonable" rate of return on its investment. Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

Of course, these principles of ratemaking do not allow a utility to operate irresponsibly and do not "guarantee" a satisfactory rate of return. Nevertheless, they do provide electric utilities with a remedy if the principles are not followed, and thus considerable assurance that the utilities will remain financially viable in the long term through the recovery of just and reasonable rates.

In sum, I believe (and will be surprised if the Staff does not agree) that power reactor licensees should be permitted to recover routine decommissioning costs through a variety of options, including negative net salvage depreciation. Of course, there may be unusual circumstances where due to unique corporate organization or financial instability the Staff might attempt to impose as a condition of licensing some funding arrangement. The case-by-case approach would be compatible with the review and approval of most licensees on a routine basis and the possible imposition of unique conditions on a few.

However, assuming that the Commission will be satisfied generally with permitting licensees to utilize a range of funding options to recover routine decommissioning costs, there remains an issue which is troublesome to the NRC Staff. The Staff is concerned that if a power reactor must be decommissioned prematurely, licensees may not have accrued or otherwise have available the funds necessary to decommission. The Staff is considering regulatory options to cover this contingency.

In my view, the Staff has overstated the likelihood of premature decommissioning, and as such has emphasized that remote possibility as a matter for principal consideration in the rulemaking proceeding. NUREG-0584 indicates several times that the Staff assumes that premature decommissioning is a highly probable event. It concludes its analysis of funding options under the assurance criterion with the following observation:

> "All three alternatives, but particularly the latter two [sinking fund and depreciation reserve], do not allow <u>sufficient</u> accumulation of funds if a facility <u>is forced to be shut down prematurely</u> or if a utility encounters financial difficulties." (NUREG-0584, at p. 19 (emphasis added)).

Likewise, the report downgrades the depreciation option as "fraught with uncertainty" (NUREG-0584, at p. 38), apparently in part because of the assumption of a high probability of premature decommissioning.

While NUREG-0584 places considerable emphasis on the premature decommissioning issue, it fails to analyze or even discuss the <u>likelihood</u> of premature decommissioning. The likelihood of an event which would necessitate a premature decommissioning (in contrast to an occurrence necessitating repair prior to restart) is extremely low. If this low probability is considered together with the fact that the need to prematurely decommission will not, ipso facto, occasion the bankruptcy of the licensee, then the Staff's preoccupation with the premature decommissioning question becomes even more tenuous.

This is not to say, of course, that the remote possibility of premature decommissioning should not be considered. I do suggest, however, that a general regulation imposing burdens on NRC licensees to protect against the occurrence of a highly improbable event is unreasonable. Again, if the Commission were to evaluate the financial qualifications issue on a case-by-case basis, it could retain the flexibility to fashion special conditions where justified by unusual or unique situations.

Simply stated, I disagree with the notion that all NRC licensees, regardless of system structure or strength, should be burdened with a regulation imposing a condition to account for a highly remote contingency, particularly where no consideration has been afforded to the factors of the particular case. We shall have the views of the NRC Staff on the matter in July.

IV. CONCLUSION

It does not appear that final NRC Regulations governing decommissioning activities will be promulgated within the next two years. Staff research and study on several technical issues (such as residual radioactivity limits) are ongoing, and apparently will not be completed soon. This schedule permits NRC licensees and economic regulators the time necessary to establish decommissioning cost recovery methods without undue influence from NRC regulations. It may not always be so, and for that reason you should focus your attention on the decommissioning question at the earliest possible time.

In any event, I believe that the major regulatory impacts which will be experienced when the regulations are promulgated will be felt in the economic area. While the technology aspects will not be faced until decommissioning activities are undertaken many years hence, the economic aspects will likely have immediate impacts on the way NRC licensees do business. For this reason the legal and financial aspects of decommissioning bear close watching as new regulations are developed.

TWENTY-SECOND SESSION, Rriday, May 23 - 8:30 a.m.

RAILROAD DEREGULATION AND THE CAPTIVE SHIPPER

CHAIRMAN: Hon. Richard D. Cudahy, Circuit Judge
United States Court of Appeals
Board of Directors, Iowa State Regulatory Conference

SPEAKERS: William Dempsey, President
Association of American Railroads

William L. Slover
Attorney
Slover & Loftus

DEREGULATION AND THE "CAPTIVE SHIPPER"

William H. Dempsey
President
Association of American Railroads

I think the topic we're discussing at this session today -- the impact of railroad deregulation on captive shippers -- is quite timely.

I say this because railroad deregulation is on the way. And it will obviously have tremendous impact on everyone -- railroad, captive shipper, non-captive shipper, rail supplier, rail labor, rail competitor. Everyone.

Having said that, however, let me say one other thing.

We're putting the cart before the horse in focusing on the impact of deregulation on so-called captive shippers.

Before we can intelligently discuss that impact -- and assess its meaning -- we have to first look at the reasons behind deregulation . . . the forces that have impelled railroads and other groups to favor deregulation. So I propose to do that first.

It seems to me -- indeed, it seems to the overwhelming majority of the railroad industry -- that the logic behind deregulation is compelling.

Why?

It begins with the basic rationale for regulating railroads in the first place.

Railroads in 1887 had what virtually amounted to a transportation monopoly. This obviously gave them the potential to exercise enormous economic power. Regulation was seen as a way to temper that power -- to protect against any abuse of that potential power. So regulation was designed to serve that purpose -- the purpose of restraining a perceived monopoly.

But regulation served another purpose as well. Because railroads were perceived as having a monopoly, the theory grew that they could afford to finance the costs of certain social programs from their profits. So regulations were also promulgated to make railroads bear the cost of meeting various social goals that private businesses are not normally called upon to meet.

Later, regulation of railroads took on yet another aspect. Other transportation modes began to develop. It was felt that their development could be impaired if railroads were permitted to exercise the powers that their near-monopoly allegedly gave them. So railroads were further regulated in a manner calculated to restrict their ability to compete while their new competitors were regulated primarily in ways that would protect them from facing competition.

This sort of regulation has continued to this very day. All railroad freight traffic is regulated. But less than half of all truck freight moves under regulation -- only 44 percent according to the most recent figures. And barge traffic is even less regulated. Only 15 percent of all water-borne freight in this country is subject to regulation.

What is the effect of this sort of regulation?

For railroads there are two main effects. Some railroad regulation increases railroad costs. Other regulation reduces railroad revenues. And some manages to give railroads the worst of both worlds. It increases costs while, at the same time, reducing revenues.

When a railroad cannot abandon a money-losing line, its costs are being increased . . . by regulation. When a railroad has to repair freight cars for which there is no long-term need, its costs are being increased . . . by regulation. When a railroad has to shuttle empty freight cars back and forth between yards, its costs are being increased . . . by regulation.

Then there's the other side of the picture. When a railroad cannot raise its rates to recover inflation-based cost increases, its revenues are being reduced . . . by regulation. When a railroad has to subsidize rates for a commodity, its revenues are being reduced . . . by regulation. When a railroad cannot lower rates to gain new business or meet the competition's prices, the railroad revenues are being reduced . . . by regulation.

And, finally . . . the worst of both worlds.

When a railroad has to break up a unit train to serve small volume shippers, its costs are being increased and its revenues are being reduced . . . both at once . . . by regulation.

Enough!

The rationale for this sort of regulation has disappeared. That rationale was a railroad monopoly. That monopoly hasn't existed for decades. Far from it. Railroads today move a bare 35 percent of the nation's intercity freight. Other modes move the rest.

Indeed, that 35 percent figure may actually overstate the railroad share because it is based on ton-miles, not originated tonnage. Railroad originated tonnage has actually dropped since the late 1940s -- by almost 10 percent. That of rail competitors has increased by about 90 percent. Even in terms of ton-miles, rail competitors have done much better than railroads -- growing almost 130 percent since 1947 compared to a 25 percent growth by railroads.

Declining market share for railroads has meant declining earnings.

Last year, railroads had their best year of the decade, as far as earnings were concerned.

Last year, railroads earned almost half as much as railroads could have earned had they invested their money in a passbook savings account at a savings and loan.

2.7 percent.

That's what railroads earned on investment.

The ICC says railroads need to earn 11 percent over the long-term in order to make the expenditures necessary to provide adequate freight service and provide a reasonable return on investment to shareholders.

Not one of the country's 20 largest railroads earned 11 percent last year. And between them, these railroads provide 95 percent of the country's rail freight service.

Without adequate earnings, railroads will be unable to make the expenditures necessary to meet the demands placed upon them during the '80s. Some experts say railroads face a capital shortfall of $20 billion over the coming decade.

The nation cannot afford that. The nation will need railroads more and more over the coming decade.

Why?

A lot of reasons.

Environment, for one. Economic efficiency, for another. Land use, for a third.

But there's another reason that stands out above all others.

Energy.

Railroads are up to four time as energy efficient as trucks. Railroads are also slightly more energy efficient than water carriers on the average, given the greater circuity of most barge routes.

A country whose economy is based on the free movement of goods from region to region cannot afford to ignore the inherent energy efficiencies of railroads if it is to solve its energy problem without totally disrupting the economy.

Railroads cannot raise the money necessary to meet those demands without increasing revenues and reducing costs. And regulation makes both difficult.

Hence, the reasons why railroads favor deregulation.

Now to the captive shipper.

If only I can find him or her.

Because the captive shipper is a little like the will-o-the-wisp.

Not there when you try to find 'em.

At least, not very often.

I realize that a good many shippers claim to be captive. But those claims generally fall apart under close examination. Take, for example, the grain shipper.

A bulk commodity moving over long distances. A classic example of the so-called captive, right?

Wrong.

Not since 1974 have the railroads originated as much as half of the country's grain tonnage. In many major grain markets, the rail share has plummeted during recent years. In 1970, over half of the grain moving into Chicago went by rail. By 1977, it was less than one-fifth. Three-quarters of the Pacific Northwest's grain moved by rail in 1967. A decade later, market share had dropped by one-third. South Dakota motor carriers increased their market share from 19 percent to 34 percent between 1975 and 1978.

Grain simply is not a rail captive commodity any longer. Indeed, a University of Minnesota professor in 1978 published a study comparing the economic and operating data for 40 Minnesota grain elevators that lost rail service with 64 nearby elevators that retained rail service.

His study found that loss of rail service did not automatically put the elevators without rail service at a disadvantage. In fact, the elevators without service grew more rapidly than those that retained service -- by 68 percent over the six-year study period, compared to 61 percent for elevators that retained rail service.

Hardly a captive. But I would be willing to bet if you had asked those elevator operators -- before they lost rail service -- whether they were rail captive, each would have said yes.

Other bulk commodity shippers also tend to think of themselves as being rail captive. And once again, I would submit that most are not.

For example, modes other than railroads now participate in 80 percent of all iron ore movements. And about 50 percent of all coal movements.

The fact is, competition in this country is pervasive. And in no segment of the economy is there more present and potential competition than within freight transportation.

Intense intermodal competition for the movement of industrial goods is the established reality. Highways reach every part of the United States and motor carriers now successfully compete with railroads for almost all types of freight -- even that involving bulk commodities and long hauls.

The inland waterway system is not as extensive as the highway system -- but only because the Army Corps of Engineers has not yet thought of a way to justify creation of an Interstate Waterway System as pervasive as the Interstate Highway System.

As important as this type of competition is in eliminating any vestige of a railroad monopoly, it is not the only type of competition that a railroad faces in determining its rate structure. There are at least two other forms of competition that are extremely important -- competition between geographically separate producing centers and competition between products that can substitute for each other.

Examples of geographic competition abound. Steel from Chicago competes with steel from Pittsburgh and both compete with imports. Oranges from California compete with oranges from Florida. Sulfur from the Gulf Coast competes with sulfur from Canada. U.S.-made automobiles compete with imported vehicles.

Railroad managements are not stupid. A railroad that is already making an adequate profit on steel from Chicago, for example, is not going to so raise rates on that movement that the business is lost to a competitor that happens to haul steel from Pittsburgh. Nor is a railroad from Iowa going to raise its grain rates if it means that it loses profitable business because a foreign grain importer finds he can buy Canadian grain cheaper.

Examples of product competition are also easily found. Cane sugar from the South competes with beet sugar from the Midwest. Glass containers compete with metal and plastic. And steel competes with aluminum. No railroad with any marketing sense at all is going to so increase its rates as to drive away profitable business.

Given all of the types of competition that abound, it seems quite clear that there are not many truly captive shippers around. There may be a few. But not many.

Last year, the Interstate Commerce Commission asked an outside consultant to study the issue of captive shippers. When the study was completed, the results surprised quite a few people in Washington who had been hearing so much about captive shippers.

It did not surprise railroaders, however. Because that exhaustive study found that only 5-to-15 percent of all rail shippers are truly captive and subject to the potential of monopoly abuse.

I might add here that in Canada railroads were substantially deregulated 13 years ago. Joseph Hanley, the director general of the Canadian Transport Commission, was asked to testify in the Senate about the impact of deregulation in Canada.

Eventually the discussion got around to the captive shipper. And Mr. Hanley told the Senators that they had not found that to be a problem in Canada. In fact, he said, only two shippers had even claimed to be victims of rail monopoly power -- and the CTC, which retained jurisdiction over captive shippers, denied both claims.

He also made another interesting point -- one that is highly relevant to a discussion of the impact of deregulation on the captive shipper. He said that railroad and shipper both developed new expertise in dealing with each other and in negotiating rates. He said there is a constant negotiating process going on between railroads and shippers with new rates going into effect -- sometimes up, sometimes down -- on a continuous basis.

It seems likely that something of that sort will happen in this country. Particularly, it would seem quite likely that the railroads and the more rail-dependent shipper will develop a new expertise in dealing with one another and that ultimately much of this business will move under contract rather than common carrier rates.

This has advantages for both participants. For the railroad, it gives the necessary volume guarantees that permit it to make the needed investments in plant and equipment at the most favorable interest rates. For the shipper, it provides the necessary service and rate guarantees that allow the shipper to make appropriate marketing and investment plans.

One other point also needs to be mentioned. Railroad rate regulation will not be as drastically curtailed in this country as it was in Canada. None of the legislation being considered by Congress would grant U.S. railroads the degree of rate freedom enjoyed by Canadian railroads. Both major pieces of legislation -- S. 1946, the Railroad Transportation Act of 1979, and H.R. 7235, the Rail Act of 1980 -- retain the principle of maximum rate regulation for so-called captive shippers. So there will be regulatory relief for the truly captive shipper.

But I would not expect that relief would be used to grant the captive bargain basement rates. It simply is not going to happen. Because competition is so extensive -- and because railroads are falling far short of meeting their capital needs -- the more rail-dependent shipper can expect to pay a higher percentage ratio of revenue to variable cost than the less rail-dependent shipper. And I would argue that this is fair.

So long as the traffic whose rates are being held down by market forces is making any contribution to fixed costs, the shippers who pay higher rates benefit. Because without that contribution from the first shipper, their rates would have to be even higher.

There is another point, too. The rail-dependent shipper stands to be harmed more than the non-rail-dependent shipper by anything that impairs the railroad industry's ability to raise the money to provide adequate service. The shipper who isn't dependent on rail service but uses it anyway can simply shift his business to another mode in the event of a collapse of the rail system. The true captive cannot.

Just as the more rail-dependent shippers have the most to lose from a continuation of the railroad industry's financial decline, so do they have the most to gain from the strengthening of the rail system. And, to my mind, that means the rail-dependent shippers have the most to gain from deregulation.

Deregulation will lead to improved rail earnings -- and improved rail earnings are essential to any strengthening of the rail system.

Some of this improvement in earnings will come from cost reductions through easier restructuring. But even more will come from increased revenues, partly from increased rates on some traffic and partly from new business that can be gained through rate experimentation.

We already have dramatic evidence of the degree to which deregulation can help railroads gain new business. It involves fresh fruits and vegetables. For the last quarter century, the rail market share has been declining. By the end of 1979 that market share was down to 11 percent.

But then last May the ICC deregulated most fresh fruits and vegetables. And business soared. Rail traffic jumped 32 percent after deregulation. I might add that prior to deregulation, rail traffic was down 5 percent.

Because other regulatory restraints were also eased, railroads were able to make important strides in improving utilization of the refrigerated cars and trailers in which the perishables are moved. It involved creation of special rates to fill the equipment with non-perishable traffic on what used to be an empty back haul from East to West.

So the bottom line of deregulation, it seems clear, will be improved rail service -- made possible by improved rail earnings. And no one will benefit more from that improved service than the most rail-dependent shippers.

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RAILROAD DEREGULATION AND THE CAPTIVE SHIPPER

William L. Slover
Attorney
Slover & Loftus, Washington, D. C.

Defining The Captive Shipper

The creature which has become known as the "Captive Shipper" had its genesis in the Railroad Revitalization And Regulatory Reform Act Of 1976 ("4-R Act"), 1/ amendments to the Interstate Commerce Act ("Act"). 2/ Prior to the enactment of the 4-R Act, all users of railroad transportation services were entitled to protection from unlawfully high freight rates 3/ and hence no need or occasion arose to define or establish the extent or degree of market power which a carrier or carriers enjoyed over a shipper's transportation business. 4/

The impetus for the passage of the 4-R Act was the rash of railroad bankruptcies in the northeast which culminated in the collapse of Penn Central. Whether correct or not, the Congress concluded that the failure of Penn Central and the financial ills of many other railroads were directly attributable to unnecessary and repressive regulation by the Interstate Commerce Commission ("I.C.C.") pursuant to the terms and provisions of the Act. 5/ The fall of the railroads from surface transportation ascendancy and their loss of traffic to competing modes such as trucks, barges, and even air carriers, were felt to be due in part to overly restrictive rate

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1/ Pub. L. No. 94-210, 90 Stat. 33 (1976).

2/ At the time of enactment of the 4-R Act, the Act was set forth at 49 U.S.C. §1 et seq. On October 13, 1978, the Act was recodified without substantive change (See Act of October 13, 1978, Pub. L. No. 95-473, 92 Stat. 1337) and is now codified at 49 U.S.C. §10101 et seq.

3/ The pertinent part of the Act was then §1(5) which prohibited railroads from charging "unreasonable" rates.

4/ A shipper is generally understood to be the party who pays the freight charges and may be a consignee and/or a consignor.

5/ Others differ on the reasons for the failure of Penn Central. See: Robert Sobol, The Fallen Colossus, (Weybright & Talley, 1977).

regulation. 6/ To remedy this situation and to enable the railroads to compete more equally with trucks and barges, the 4-R Act sought to free railroad pricing from federal regulation in transportation markets where they encountered competition. Thus Congress declared amongst its new railroad policies to:

> permit railroads greater freedom to raise or lower rates in competitive markets....

4-R Act §101(b)(3).

To implement its newly enunciated policy, it became necessary for the Congress to delineate which markets were competitive and which were not. The tool chosen was the market dominance concept introduced through Section 202 of the 4-R Act. Under the new scheme, the I.C.C. could not find that a railroad rate was too high unless the carrier offering the rate enjoyed market dominance over the traffic involved. Market dominance was defined by Congress in the 4-R Act as "an absence of effective competition from other carriers or modes of transportation, for the traffic or movement to which a rate applies...." 4-R Act, Section 202(b). The whole concept of market dominance is that I.C.C. regulation is unnecessary where the forces of competition are effectively at work, because those forces will operate to keep rate levels at reasonable levels. However, where competition is insufficient to insure that rates will not exceed a reasonable level, the I.C.C. retains the authority to regulate rates to protect shippers from monopolistic or oligopolistic rail carrier charges. Thus, as the Senate Commerce Committee has explained:

> ...the test will be whether the market itself is sufficiently competitive to insure just and reasonable rates.

S. Rep. No. 94-499, 94th Cong. 1st Sess. 47 (1975). Pursuant to a 4-R Act directive, the I.C.C. has promulgated rules for the admin-

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6/ See: S. Rep. No. 94-499, 94th Cong. 1st Sess. 11. This theme is reiterated over and over again in the hearings which preceded the 4-R Act. See Transportation Act of 1972: Hearings on H.R. 11824 H.R. 11826 and H.R. 11207 Before The Subcomm. on Transportation and Aeronautics of the House Comm. on Interstate and Foreign Commerce, Ser. No. 92-77, pts. 1-4, 92d Cong. 2d Sess. (1972); Surface Transportation Legislation; Hearings on H.R. 12891, H.R. 5385, H.R. 13487, H.R. 10694 and S. 1149 Before The House Comm. on Interstate and Foreign Commerce and the Subcomm. on Transportation and Aeronautics, Ser. No. 93-85, 93d Cong., 2d Sess. (1974); Railroads - 1975: Hearings Before The Senate Comm. on Commerce and the Subcomm. on Surface Transportation, Ser. No. 94-31, pts. 1-5, 94th Cong., 1st Sess. (1975); Railroad Revitalization: Hearings on H.R. 6351 and H.R. 7681 Before the Subcomm. on Transportation and Commerce of the House Comm. on Interstate and Foreign Commerce, Ser. No. 94-38, 94th Cong., 1st Sess. (1975).

istrative application of the market dominance standard. 7/

The users of railroad services where market dominance exists while not so referenced in the law, shortly became known in transportation circles as "captive shippers." Their plight under the 4-R Act has received considerable notoriety. The most visible components in the captive shipper category are the large receivers of bituminous coal. Most of these receivers are electric utilities although there are many industrial enterprises where coal traffic is captive to the railroads.

Railroad Pricing After The 4-R Act

While a key 8/ objective of the 4-R Act was the deregulation of railroad pricing in competitive markets as a means to restore the financial health of the railroads, there has been a dearth of competitive or innovative pricing by the railroads in markets where they encounter competition. In a word, the railroads have made little or no use of their new freedom from rate regulation, prompting former Commission Chairman A. Daniel O'Neal to assert the following to a Congressional committee:

7/ See 49 C.F.R. §1109.1. These regulations establish three (3) rebuttable presumptions of market dominance: (1) where the involved rail carrier or carriers possess 70 percent or more of the relevant transportation market (49 C.F.R. §1109.1 (g)(1)); (2) where the issue rate exceeds by 60 percent or more the variable cost of service (49 C.F.R. %1109.1 (g)(2)); (3) where a shipper has made a substantial investment in rail related facilities (49 C.F.R. §1109.1 (g)(3)). Also promulgated was a presumption of a lack of intramodal competition which is established when a proposed rate is subject to rail rate bureau action (49 C.F.R. §1109.1 (f)).

Recently the Commission has proposed to scrap its current presumptions and substitute new administrative regulations. See Ex Parte No. 320 (Sub No. 1), Rail Market Dominance And Related Considerations, 44 Fed. Reg. 3353 (1980) (notice of proposed rulemaking).

8/ Although rate deregulation is an important aspect of the 4-R Act, the Act is over 130 pages in length and most of it is totally unrelated to the deregulation of rates.

> ...the central problem today ... is with the failure of the railroads to provide competitive service at competitive rates on competitive traffic. 9/

The fact of the matter is that the railroads sought and achieved pricing freedom in competitive markets, but have chosen to make no use of these freedoms. Instead, the railroads have pursued a widespread program to exploit rail customers who have no alternative to railroad service. With a minor exception here and there, this exploitation, which has invariably involved coal traffic, has led to a wave of litigation before the I.C.C. and the federal courts of unprecedented dimensions. 10/ These disputes involve receivers throughout the nation.

Thus, the 4-R Act which was intended to usher in a new era of regulatory freedom for railroads in competitive markets has instead fostered one of the most intense periods of railroad regulatory activity since the initial passage of the Act to regulate railroads in 1887.

In the words of the Congress, the 4-R Act changes were:

> ... intended to inaugurate more competitive pricing in rail transportation, but they are not intended to authorize or to be applied to permit predatory competitive conduct.

S. Rep. No. 94-595, 94th Cong. 2d Sess. 134 (1976). As we have noted, however, the railroads had little or no interest in competitive pricing, but in reality were interested primarily in the exploitation of traffic as to which they enjoyed monopoly or quasi-monopoly powers; i.e. the captive traffic of the captive shipper.

9/ Coal Rates And Federal Railroad Regulation: Oversight of the Railroad Revitalization And Regulatory Reform Act of 1976: Hearings Before The Subcommittee on Oversight And Investigations of the Committee on Interstate and Foreign Commerce House of Representatives, 96th Cong., 1st Sess. 488 (1979).

10/ See Appendix A for a listing of coal cases currently pending before the federal courts. For a comprehensive analysis of the captive shipper problem in coal transportation, see Railroad Coal Rates and Public Participation: Oversight of I.C.C. Decisionmaking, Report Together With Separate Views By The Subcomm. On Oversight And Investigations of the House Comm. On Interstate and Foreign Commerce, Comm. Print 90-IFC 40, 96th Cong. 2nd Sess. (1980). The Subcommittee found that:

> The Interstate Commerce Commission has allowed rampant railroad rate increases for hauling coal since the enactment of the Railroad Revitalization And Regulatory Reform Act.

Id. at 2.

Fate of The Captive Shipper Under The 4-R Act

The 4-R Act which created the captive shipper also led to an "open season" on increased prices for captive traffic and particularly high volume coal traffic. Some of the many coal movements targeted, after the 4-R Act, for major price increases by the railroads were the following:

MOVEMENT	RECEIVER	INCREASE
Montana to Duluth, MN	Minnesota Power & Light	60%
Montana to Detroit, MI	Detroit Edison	45%
Wyoming to Council Bluffs, IA	Iowa Power & Light	37%
Wyoming to Flint Creek, AR	Southwest Public Service Co.	31%

This unintended and unfortunate result came about because the 4-R Act which was hailed as a forerunner of the now popular, regulatory reform movement did little in the way of altering, clarifying, or revising the ways, means, and mechanics of how maximum railroad prices are to be determined. In other words, while the 4-R Act created the captive class of shippers who alone would be entitled to the protection afforded by federal rate regulation, it was silent as to what these protections would be. In its zeal to deregulate competitive transportation, the Congress neglected monopoly traffic which, as it turned out, became the center of controversy. Indeed, the Congress in the 4-R Act did worse than ignore the standards for regulating rates on monopoly traffic since it added a general and confusing, new provision misnomered as a Rule Of Ratemaking 11/ which provided that railroads were entitled to "adequate revenues" and instructed the I.C.C. to assist the railroads in attaining adaquate revenues. Regrettably, the I.C.C., after ignoring the existence of this little-noticed provision for over a year following the passage of the 4-R Act, began in late 1977, 12/ at the urging and behest of the railroads to equate "adequate revenues" with a reasonable rate of return; to equate a reasonable rate of return with the current cost of capital; and finally, in coal rate cases to try to set rates so high as to markedly improve the railroads' overall rate-of-return solely from coal revenues. Stated differently, the 4-R Act which was designed to foster flexible railroad pricing in competitive markets, has led to I.C.C.-sanctioned demand pricing in inelastic markets. The existence of the phenonena was recently acknowledged and summarized as follows by the I.C.C.'s new Chairman:

11/ 4-R Act §205, now codified at 49 U.S.C. §10704 (a)(2).

12/ See Incentive Rate On Coal-Cordero, Wyoming To Smithers Lake, Texas, 358 I.C.C. 537 (1977); Incentive Rate On Coal-Gallup, New Mexico To Cochise, Arizona, 357 I.C.C. 683 (1977).

> Just take a minute to think what the real issue is concerning coal rates. The issue is certainly not whether coal rates should cover the direct cost of moving coal. We are all agreed that all traffic should bear its direct costs. Instead, the controversy is over the necessity for coal traffic to bear a more than proportionate share of the railroads' unallocable system costs. At least in the short run, I just don't see any alternative to throwing a lot of those system costs onto coal rates if we want to keep the railroads operating....13/

Here we have a candid and frank admission by the agency's Chairman that it is pursuing a ratemaking policy which encourages the sacrifice of the captive shipper for the purpose of attaining overall carrier prosperity. There are numerous obvious defects in a ratemaking policy wherein inelastic traffic is purposefully exploited to cross-subsidize activities in competitive markets. We will touch upon but two here.

Error In Existing Policy Of Exploitation Of The Captive Rail Shipper

A. True Financial Status Of The Railroads

Railroad reform and deregulation momentum invariably stem from gloomy predictions over the future of the nation's railroads. Only one year ago, the then Transportation Secretary Brock Adams stridently asserted in a White House press conference that the nation's railroads were on the brink of economic disaster and that without immediate help, nationalization was imminent. 14/ Since that day, most of the nation's railroads have experienced prosperity and have enjoyed the greatest profits in their histories. These profits, in turn and in part it might be added, go into ambitious nonrailroad, diversification programs typified by the Southern Pacific's recent cash acquisition of the Ticor Insurance Company for $250 million. How, one asks, can the railroads be on the verge of bankruptcy and yet be awash in cash? The answer is actually quite elementary. It lies in the reliance upon return on book value as a gauge of the financial strength of the components of this industry. With some exceptions, rates of return for railroads are very low in relation to other industries. Billions of dollars in additional revenues would be required to enable them to earn the current costs of capital on the equity portion of their investments.

13/ Darius W. Gaskins, Jr., Speech Before The American Mining Congress, May 6, 1980, Chicago, Illinois.

14/ White House Press Briefing By Secretary Brock Adams, Department of Transportation (March 23, 1979).

The rate base - rate of return methodology is justified by reference to the opportunity cost theory. A dollar of capital employed in a regulated industry must earn what the economy loses by not employing it elsewhere. To find what it might have earned elsewhere, one must simply determine what 40 cents of debt and 60 cents of equity (the industry average debt/equity mix) could have earned in alternative but comparable employment. This methodology is appropriate if one were considering the building of a new railroad, for one would know just how much capital must be attracted from alternative uses. Unfortunately, it is not appropriate as a measure of financial health for the U.S. railway industry as it exists today. The reason is not that the capital is sunk, for in the long run, even sunk capital must be rebuilt. The reason is that no one really knows how much capital is presently employed in U. S. railways and much of what is, has little value as rail property *per se*. Because the railroad rate base is unregulated and overstated there is reluctance to employ market rates of interest in an arithmetic multiplication exercise that yields hundreds of millions of dollars in supposedly justified returns. Another separate problem with rate of return analysis in the context of the rail industry is the influence of betterment accounting. This system of accounting expenses many dollars of investment that would be capitalized and depreciated under depreciation accounting. As a consequence, in times of heavy investment in plant such as the present, this accounting methodology results in significantly lower income and return figures than would obtain under depreciation accounting. The railroads would enjoy a gigantic windfall at the expense of captive shippers if they become entitled to a "reasonable rate of return" calculated by applying the current cost of capital to their book investment. For example, in 1976 BN had a rate of return of 2.5 percent. To achieve 11 percent it would have to receive additional revenues of $235 million per year. All or most of these increases would accrue to present stockholders. Those who persist in defining the railroad problem in terms of rate of return are, in fact, part of the railroad problem. The following warning of former Congressman Moss has remained largely unheeded:

> ...the courts, the regulatory agencies and the investors must be persuaded to give up the rate of return concept, as Congress has, not because it is illegal or unlawful, or undesirable; but because it is impractical. They cannot make it work, they cannot enforce it; they can only continue to waste more of this nation's resources in a fruitless quest for that which is impossible.
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> Congress has already led the way. In the Railroad Revitalization Act of 1976, Congress directed the I.C.C. to substitute the "cash flow test" for the rate of return,...for determining revenue need....

124 Cong. Rec. H 7682-83 (daily ed. Aug. 1, 1978). Until the financial status of railroads is gauged by a measure other than rate of return, we will have a railroad problem in this country whether one in fact exists or not.

B. Cross Subsidization

If as the captive shippers contend, the railroad industry is not nearly as bad off as it makes out, there may be no need for the present cross-subsidization program which is operated largely at the expense of the captive coal shipper. However, even if the railroad industry had bona fide financial ills, it is unsound regulatory policy to permit unregulated and elastic markets to be subsidized with revenues from captive coals. Under the I.C.C.'s notions of so-called differential pricing, it requires captive traffic to pick up the slack for competitive traffic over which it has no jurisdiction and some of which, for all it knows, the railroads could be hauling for free. The present policy of having captive shippers cross-subsidize other traffic is an indefensible by product of the misguided and undiminished Congressional and administrative emphasis on deregulation.

Conclusion

The 4-R Act is about to be superseded by new legislative proposals now pending before the Congress. Whether the captive shipper improves his lot thereunder is, at present, problematical. In the final analysis, it is ironic that the supposedly consumer-oriented railroad deregulation movement will, if enacted, come at an immense expense financed largely out of each consumer's pocket in the form of greatly increased monthly electric bills.

APPENDIX A

Petitions For Review Filed In U.S.
Circuit Courts From I.C.C. Coal Rate Decisions

Southwestern Electric Power Company v. I.C.C. and United States, No. 79-2701 (5th Cir., filed July 23, 1979).

Southwestern Electric Power Company v. I.C.C. and United States, No. 79-2082 (5th Cir., filed May 3, 1979).

Burlington Northern, Inc. and Kansas City Southern Railway Company v. United States and I.C.C., No. 79-1547 (D.C. Cir., filed May 25, 1979).

Systems Fuels, Inc. and Arkansas Power & Light Co. v. United States and I.C.C., No. 79-2491 (5th Cir., filed June 22, 1979).

Nevada Power Company v. I.C.C. and United States, No. 79-7504 (9th Cir., filed October 1, 1979).

Utah Railway Company v. United States and I.C.C., No. 79-2059 (10th Cir., filed September 28, 1979).

Union Pacific Railroad Company v. United States and I.C.C., No. 79-1840 (10th Cir. filed August 17, 1979).

San Antonio, Texas Acting By And Through Its City Public Service Board v. United States and I.C.C., No. 78-2051 (D.C. Cir., filed October 25, 1978).

Burlington Northern, Inc. v. United States and I.C.C., No. 78-2307 (D.C. Cir., filed December 21, 1978).

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Alabama Power Company, et al. v. United States and I.C.C. No. 79-2090 (D.C. Cir., filed September 17, 1979).

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Seaboard Coastline Railroad Company v. United States and I.C.C., No. 79-2001 (D.C. Cir., filed August 29, 1979).

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Burlington Northern, Inc. v. United States and I.C.C., No. 79-3777 (6th Cir., filed December 28, 1979), No. 80-3020 (6th Cir., filed January 7, 1980), No. 80-3161 (6th Cir., filed March 11, 1980).

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TWENTY-THIRD SESSION, Friday, May 23 - 10:15 a.m.

Concurrent Session J-1

EFFECTS OF AIRLINE DEREGULATION

CHAIRMAN: Hon. John F. Vukasin, Judge
Superior Court, State of California
Board of Directors, Iowa State Regulatory Conference

SPEAKERS: Raymond J. Rasenberger, Esq.
Zuckert, Scoutt & Rasenberger

Charles Barclay, Staff Director
Senate Aviation Sub-Committee

AIRLINE DEREGULATION

Raymond J. Rasenberger
Zuckert, Scoutt & Rasenberger

I. How Airline Deregulation Came About

A review of the unusual combination of circumstances which led to drastic reform of an industry which had enjoyed a favorable public image under existing regulation:

- inept overregulation by the agency prior to mid-70's
- strong theoretical support among influential academicians
- the example of airlines not subject to CAB regulation
- the choice of new leadership at the CAB which favored deregulation
- the adoption of deregulation by the CAB under the former statute and a favorable economic climate
- political advantages perceived by both the Ford and Carter administrations
- the dynamics of the legislative process and role of key leaders
- divisions within the airline industry

Result: far more drastic statutory change than opponents had expected or supporters had hoped for, including the unprecedented sunset provision.

II. Rate Regulation Under the Airline Deregulation Act

- Rate regulation prior to the mid-70's, first by ad hoc ratemaking and later under the comprehensive regime of the DPFI (Domestic Passenger Fare Investigation).
- Easing of regulation under the Kahn regime; de facto repeal of DPFI and introduction of administrative zone of reasonableness.
- The new public interest test and statutory zone of reasonableness for passenger fares; its further extension by CAB order.
- The "standard industry fare level" (SIFL) concept as required by the statute and administered by the CAB.
- Other changes now pending at the CAB including possible deregulation prior to the January 1, 1983 sunset.
- New CAB attitudes on unjust discrimination, free transportation, rebating, agency commissions, etc.

- How has fare deregulation worked in practice?

  - changes in basic fares and promotional fares since the Deregulation Act

  - the significance of fuel costs

  - results of air cargo deregulation

  - prospects for the future

III. Changes in Entry and Exit Regulation

- Regulation prior to the mid-70's

- Administrative deregulation of entry prior to the Deregulation Act by show cause and other liberalized procedures.

- The elaborate - and superfluous - new statutory provisions affecting route regulation.

- The early obsolescence of these provisions as a result of agency initiatives.

- The situation today: entry largely deregulated in advance of the January 1, 1982 sunset.

- The problem of free exit and small city service.

  - The historic setting - uneconomic small city services, creation of small subsidized airlines.

  - Service withdrawals under the new Act; community conflicts and continuing Congressional concern.

  - The "essential air service program" and the expected role of commuter airlines; pending judicial challenges.

- The role of federal subsidies. The new subsidy program under §419.

- An assessment of the impact of the new statute and future prospects.

IV. Industry Structure and Competition Under the New Statute

- Will a deregulated industry be functionally more competitive?

- Theories concerning the impact of deregulation on industry structure. Mergers and CAB merger policy since deregulation.

- The development of new entrants.

- Effect of deregulation and loss of automatic antitrust immunity on carrier conferences and agreements; CAB policies on conference regulation of agents.

- The outlook for CAB regulation until sunset and Justice Department regulation thereafter.

V. Deregulation and Consumer Protection

- The paradox of deregulation theory and continuing extensive regulation of consumer practices of carriers.

- Regulation of smoking, denied boarding practices, guaranteed air fares, rules for the handicapped, on-time performance, etc.

- Ongoing tensions within the CAB on consumer protection issues.

- The outlook.

IS AIRLINE DEREGULATION WORKING?

Charles M. Barclay
Aviation Subcommittee
U.S. Senate

Thank you Judge Vukasin, and thank you ladies and gentlemen for inviting me to join you today.

Judge Vukasin, in asking me to appear today, said that I should answer the question "Is airline deregulation working?" As you might imagine, I get that question quite a bit. And being from Washington, I usually answer with a question "compared to what?"

If you mean compared to a perfectly regulated system which matches resources to demand without error, gives every community the service level it desires, keeps airline profits up and airline fares down -- then no, airline deregulation isn't working.

However, if you mean compared to the kind of regulation Washington provided for forty years -- disallowing discount fare filing, refusing community and carrier requests for service rights in new markets, allowing carriers with dormant routes to keep other airlines from serving those unserved markets, producing one of the lowest average return on investment figures for any major industry, and encouraging competition among airlines in lounges, leather seats, and entertainment while precluding competition in prices -- then my answer is that airline deregulation is working exceptionally well.

Let me begin by briefly reviewing the state of the airline industry and its federal economic regulation in the mid-70's when the deregulation debate truly began. At that time the financial performance of the industry was poor enough to question successful access to the private capital markets. Thus, with an aging and fuel-inefficient aircraft fleet, the industry could not look forward to effecting a required fleet replacement which had become even more necessary after the Arab Oil Embargo in 1973. In addition, ROI performance along with all other financial performance measures was exceptionally poor. In short, the fixed regulatory mechanisms, stretched to include an irrational route moratorium and capacity-fixing, were boldly showing their clear inability to react to marketplace changes in a timely fashion.

What you really had was a situation where the Board limited price competition and market entry but encouraged amenity competition at the same time. The ironic result was that the CAB, by its very protection, was causing profits to be eroded through wasteful competition in excess capacity and amenities.

In the same vein, it was revealing to learn just how pervasive regulation had become and how far the CAB had inserted itself between a willing seller and a willing buyer. Let me cite a few of many examples. May a carrier take race horses from Florida to the Northeast? -- the CAB had to decide that. May an air taxi acquire a 50 seat airplane? Is it a deceptive practice for employees of a foreign airline subsidiary to wear uniforms that look like those of the parent? A carrier wants to issue a special fare for skiers; if there's no snow, they'll return the skiers home without charge. Should the CAB let them? The list goes on but you get the idea.

The fact is that the essence of a dynamic economy is change. Race horses have to be flown today but maybe not yesterday or tomorrow. The ultimate question we ended up facing was whether five humans, however well qualified, could sit at the CAB and effectively monitor and adjust 64,000 domestic markets for price and service. If one can divide, the answer is obvious.

Regulation had truly become an obstruction to the effective operation of the markets. Given the financial state of the industry and its requirements for the future, the choices were to either increase dramatically the regulation of the industry or to go in the opposite direction and dismantle the regulatory mechanism, thus allowing the forces of the marketplace to allocate resources. The latter proposition was not only feasible, but when you think about it, the airline industry is ideally suited to the marketplace. You have a totally mobile resource which can be shifted to where the most people demand it, and the barriers to entry are most reasonable although not low.

So airline deregulation became the law in 1978. It was very clear that the industry would undergo an economic rationalization as a result of this new market freedom. This meant that we could expect some transition problems and that certainly has been the case. Obviously, moving an industry from 40 years of strict economic regulation to the workings of the competitive marketplace doesn't happen without some dislocation. But the emperical evidence is clear that overall, the nation's air traffic system is far better off.

1978 was a record year for the industry -- $1.1 billion in profits for carriers; passengers saved $2.5 billion on air fares; traffic grew 16%. 1978 was a revealing lesson on what the marketplace can do but I want to skip over that year and look at 1979 results because I think they are even more revealing.

Despite a severe winter; a 57-day strike of United, the nation's largest airline; the prolonged grounding of the DC-10; a doubling of aviation fuel prices; and an economy dominated by double digit inflation; air traffic climbed 14 percent on top of the record 16 percent of 1978.

Fares are another indicator. Looking at all airline fares in 1979, the average fare increased 16 percent. Average industry costs, at the same time, went up by a staggering 48 percent. Now, I'd like to ask the unremitting opponents of deregulation to name another industry which made a profit in 1979 while their costs increased at <u>three times</u> the rate of their average retail prices. This productivity gain -- and make no mistake about it, that is exactly what it is, -- occurred solely because of the ability of the industry to adjust its existing resources to where they could be used the most efficiently to serve the greatest demand. Productivity gains of this magnitude in the airline industry are rivaled only by those achieved during the initial introduction of jet aircraft. At the bottom line, the airline passengers have saved on the order of four billion dollars in the last two years compared to fares which would have been set under the CAB's regulatory formula.

Smaller airlines have not been "gobbled-up" by the big ones as many of deregulation's opponents predicted. On the contrary, the regional airlines were more profitable than the trunks in 1979 and Texas International has twice tried to "gobble-up" a trunk airline. While there have been two major airline mergers approved, we have seen the entry into the scheduled interstate system of Southwest, World, PSA, Air California, Midway, Evergreen, Air Florida, and numerous smaller carriers. We have not seen the industry become more concentrated.

Industry profits have also improved with deregulation. As measured by the CAB, profits averaged $349 million a year between 1970 and 1976 under regulation. Profits in 1977, as defacto deregulation began, were $634 million; in 1978, $1.1 billion; and in 1979, when fuel prices doubled, $564 million -- not a bad year at all compared to the regulation era.

This year's first quarter results are not as bright. But when we review the year-end statistics and compare them to periods under regulation that experienced inflationary recession, we will continue to find the favorable advantage for deregulation.

Obviously we have some serious problems in the industry, as aviation fuel costs continue to climb and rising fares begin to erode traffic. But even a molecular knowledge of economics will instruct us not to blame deregulation for higher fuel prices and inflation. The proponents of deregulation never claimed that this change of law would immunize air transportation from these macro-economic evils.

Historically, the airlines led the way into recession and were the last ones out. That hasn't been the case this time. Unlike the past, airlines have not completely abandoned their low-fare strategies at the first sign of recession. Even with the current negative economic scene, discount and promotional fares are still readily available (in fact about 56% of today's passengers use such fares) and the carriers are holding reasonable traffic levels for the present. Airlines are not relying solely on the business traveler to carry them through.

There is certainly a limit on how high fares can go before we fall off the elasticity cliff and we may well be seeing the beginning of that now. However, the main point is that under the regulatory yoke, measured by the CAB's own fare formula, things would have been a lot worse a lot sooner. Fares would have been much higher much sooner.

What about the protection of small community service under deregulation about which much has been written? Again, we must compare deregulation results with the facts about past regulation, not compared to some idealistic view of regulation. Under deregulation not one community that wants scheduled air service has lost it. Essentially air service is guaranteed for 10 years to all communities. Some communities have, however, gotten commuter service in lieu of large aircraft service, when the passenger volumes justified the smaller aircraft. I would insert that such communities quickly find out that this is not a bad result. A classic case is Utica, New York which a couple of years ago lost 4 Allegheny flights at poor times that were carrying 34,000 passengers per year, and wound up with 17 commuter flights a day providing hourly connecting service as well as service to three new destinations carrying over 60,000 passengers per year. In fact under the first full year of deregulation service levels were up for all size communities an average of 8% over the previous period.

What was regulation's record on small communities? In the ten years prior to deregulation the scheduled, certificated airlines filed to exit 129 communities. The CAB granted 127 of 129 exit filings.

Is airline deregulation working? The answer is a matter of comparison. A deregulated U.S. airline will take you from New York to Atlanta for $80, compared to the tightly regulated international trip from London to Rome (about the same mileage) which will cost you $305.

In my opinion, the most striking flaw of the legislative debate over airline deregulation was that opponents of deregulation argued perfect regulation against imperfect competition. While proponents of deregulation argued perfect competition against imperfect regulation. But as we know our real world choices are imperfect competition and imperfect regulation. And I believe there is no doubt, that on the whole, imperfect competition is doing and will continue to do the better job.

Simple answers to complicated questions are not often available so I hope you will forgive my lengthy response to your short question. "Is airline deregulation working?" The best I can do by way of a short answer is to remind you of the warning one of our Presidential aspirants is giving to business leaders, which is that if you get into bed with the Federal Government, you're going to get more than a good night's sleep.

Thank you for your invitation and I'll be pleased to try to answer any questions you may have.

TWENTY-FOURTH SESSION, Friday, May 23 - 10:15 a.m.

Concurrent Session J-2

USE OF THE REVISED SYSTEM OF ACCOUNTS FOR PRICING PURPOSES

CHAIRMAN: Richard Walker

SPEAKERS: Edward Goldstein
Assistant Financial Officer
American Telephone Company

Donald A. Redman, Vice President -
Measurement and Budgets
General Telephone and Electronics Corporation

USE OF REVISED USOA FOR PRICING PURPOSES

Edward Goldstein
Assistant Financial Officer
American Telephone and Telegraph

Introduction:

Don Redman has, I believe, covered very well the way in which the Uniform System of Accounts fits into today's regulated pricing process. With respect to his comments on the proposed changes of the USOA, I'm quite in agreement in principle -- even though there may be some differences in emphasis between us.

There is, I believe, a very fundamental assumption that underlies the process that Don has described, and indeed the proposed revision of the USOA. This assumption is that it is necessary to know quite precisely the relationship between costs and prices of individual services and elements of services in order to prevent what the Commission called, in its decision in Docket 18128, "interservice cross-subsidization."

The prevention of interservice cross-subsidization is, in fact, the principal rationale for the proposed revision.

Cross-subsidization has become a major issue not only in almost every FCC tariff filing, but also in the more general FCC dockets, and the current debate on legislation in the Congress.

Since cross-subsidization -- its detection and prevention or control -- is at the bottom of so much activity today, including the revision of the USOA, I thought I would spend my time talking about it: what it is, what the problem is, how the problem can be fixed, and what the role of accounting (specifically the USOA) might be in the solution of the problem.

What is Cross-subsidy?

That question is not as easy to answer as you may imagine.* Intuitively, I think what people mean when they say that a service or group of services is being cross-subsidized is that the revenues for that service or group of services don't cover all of its costs, including the cost of money.

But, while revenues for a service are relatively easy to define -- after all, customers usually get billed on a service-by-service basis -- it's much harder to define what the costs are.

I don't want to argue the fully distributed vs. long run incremental cost controversy here today. I'll simply accept the outcome of FCC Docket 18128 on this issue. But you even have to be careful about what you assume about the cost of money. The simplest assumption is, and the one I'll make for my presentation here today, is that the cost of money is equal to the authorized rate of return of the firm, and that the actual rate of return is equal to the authorized one.

So, all I want to say about some of these difficulties in defining costs is that they exist. For the rest of the presentation, I'll just assume that there exists an agreed upon definition of all of the relevant costs -- so that I can concentrate on the cross-subsidization issue itself which, as we'll see, has some difficulties of its own.

Anyway, to recapitulate, I'll assume that what we mean by a service being cross-subsidized is that its revenues do not cover its costs. And since the firm as a whole earns its authorized rate of return -- if one service earns less, some other service must earn more, and thus subsidizes the service that earns less.

So, What's Wrong With That?

You might well ask that question. After all, no multi-product company that I know of earns exactly the same profit margin on every one of its products. One year, product A subsidizes product B; the next year, B subsidizes A. Products earn different margins in different years of their life cycle, and nobody gets very exercised over it.

So, as a general proposition, I don't think one can argue that cross-subsidization among services or products is wrong, per se.

The reason we're concerned about cross-subsidization in the telephone business, especially in the case of the larger telephone companies like AT&T and General, is that telephone companies furnish both monopoly services, like MTS and exchange, and competitive services, like private line channels.

Now, I want to stop for a moment to point out that, in actual fact, there really are no more monopoly services. All services have some form of more or less direct competition. But I don't think we need to get hung up on that. It's certainly true that some services have less competition than others. The main concern then becomes one of wanting to prevent the less competitive services from subsidizing the more competitive ones.

There are also other, less well articulated concerns. For example, some of the firms which compete against telephone companies do so for only relatively narrow product or service lines. These firms are concerned not only about cross-subsidies from a broad category of so-called monopoly services to the more competitive services as a group, but also about alleged cross-subsidies from one competitive service to another. For example, a firm offering only broadband digital channels might object to an alleged cross-subsidy from the narrow-band element of a digital transmission service to the broadband one.

Thus, what starts out as a relatively straightforward objective of preventing the so-called monopoly ratepayer from subsidizing the competitive services offered by the telephone company can quite rapidly turn into the most rigid pricing scheme, in which every element of every service must earn exactly the same rate of return, unless a waiver is issued by the Commission.

I should say that my reading of the various bills now in the Congress leads me to believe that this is not what Congress seems to have in mind. The bills all concern themselves with cross-subsidy -- indeed, it is a central issue -- but they seem to content themselves with wishing to prevent, or at least control, subsidies flowing from the regulated services to the unregulated, more competitive ones.

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OK, then. We've defined what we mean by cross-subsidy. And we've suggested why it is necessary to prevent certain kinds of cross-subsidies. Next, I think we need to understand what some of the problems are.

What's the Major Problem?

I think it's fair to say that the cross-subsidy problem would be relatively easy to solve if there were no joint or common costs between services. Or, to put it differently, if the production of different services did not utilize common resources.

As you know, the way in which telephone service is produced today utilizes many resources in common for two or more services. There are good reasons for this, which I don't need to spell out for this audience. Suffice it to say, that the common use of microwave towers, installation and maintenance people, buildings, trucks, administrative overhead, and so on, provides very large economies compared to having separate resources for each individual service. I don't think we need to argue about how great these economies are, whether services could have been provided equally as well with less use of common resources, whether the technology will increase or decrease the economies.... The fact is that this is the way the plant was built, and the services designed.

Thus, when we try to determine the cost of producing a particular service, we're confronted by the problem of how to allocate to that service some of the costs of commonly used resources.

There are not only the well-debated theoretical difficulties in doing this -- look at the ongoing debate on fully-allocated vs. long run incremental costs, and the debate on which fully allocated scheme, if any, makes more sense -- but there are also some very hard practical problems.

The proposed rewrite of the USOA tries to attack these problems, and Don Redmond has, I think, identified some of those difficulties.

Let me assert then that identifying and accounting for costs of individual services when there is no need to allocate joint or common costs, is relatively straightforward -- and that the central problem of detecting cross-subsidization through accounting lies in the joint and common use of resources.

Given the inherent theoretical and practical difficulties, and given the obvious self-interests of the various parties in this game, and given the lengthy regulatory and judicial processes available for resolving these controversies in an increasingly competitive environment -- you can understand why there is so much interest, in the Congress and the Commission and at AT&T, in looking for a better way than brute-force accounting to resolve this issue.

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Let's look at three ways that have been suggested: changing the production function, changing organizations, and changing the regulatory framework. What I think we'll find is (1) that there are several combinations of these three approaches that can work pretty well, and (2) that accounting plays a role in each one of them -- but that the focus of accounting shifts as we change the framework in which it must operate.

First, Changing the Production Function:

As we saw earlier, it is the joint and common use of resources by several services that creates the major problem.

Well, why not disaggregate these resources and eliminate this common use? That's easy to answer: because such disaggregation would create diseconomies.

But...if the alternative to disaggregation is a very complex and expensive accounting system, the development and operation of such a system also creates diseconomies. So, these diseconomies have to be weighed against each other.

The outcome of such an analysis is likely to be that it might make sense to disaggregate some functions rather than go to the trouble of having to keep detailed records and then make controversial allocations. But there surely will be some other functions for which disaggregation would simply be uneconomical, regardless of the cost of any reasonable accounting scheme.

I don't think we need to make a judgment today about how much of the problem can be made to go away by disaggregation of the production function. I'll just assert that not enough will go away to make this approach worth while by itself. We'll see later that, in conjunction with the other approaches, disaggregation is a useful technique.

The Next Step: Change the Organization

Separate subsidiaries for competitive services have been much in the news lately. Now, the setting up of a separate subsidiary for some services does not, by itself, solve much if any of the cross-subsidy problem.

If I own a firm that offers product A and product B, I could * set up separate subsidiaries for each product on paper, but not change any of the production function. I could be president of both subsidiaries. I could have my people paid partly by one and partly by the other subsidiary -- and all of the allocation problems would remain exactly the same.

But if some reasonable conditions are applied to the setting up of these subsidiaries I could accomplish some disaggregation of resources -- space, management, administrative superstructure, and so on -- and thus reduce the problem. But the major effect would then be to make things more visible. In particular, a regulator attempting to detect cross-subsidies could now concentrate on inter-company transactions rather than having to ferret out potential sources of cross-subsidization among the myriads of internal transactions that take place.

But what does one do about the resources that cannot be disaggregated without unacceptable diseconomies? For example, to be specific, suppose one can separate administrative overhead, marketing, engineering, etc. -- but that there is a microwave route that was used in common to provide the two services, and that could not be economically disaggregated?

Joint ownership of that route by both entities is an obvious approach, but it doesn't do anything for you in terms of solving the cross-subsidy problem. No matter how you arrange things, the problem of allocation remains, and with it the problem of potential cross-subsidy.

OK, suppose one of the subsidiaries owns the route and then charges the other entity for its use. The problem has now been transformed into determining the "fair price" for use of the route, but has not changed fundamentally.

I'm sure you're way ahead of me at this point, but I want to stop to review where I think we are.

Changing the organizational structure of a firm can do two things for you: (1) it can lead to logical disaggregation of some resources, and (2) more importantly, it can concentrate the potential for cross-subsidization at the interface between organizations, and thus simplify the surveillance problem. But it does not solve the fundamental problem which, as I've said, is the common use of resources.

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But Here is Where Changes in the Regulatory Scheme Come In:

There are two such major changes that I want to mention: (1) the introduction of marketplace forces, and (2) changes in some regulatory objectives.

A couple of minutes ago, when I talked about having one of the organizational entities own the microwave system, and charging the other entity for its use, I suggested that the cross-subsidy problem was transformed, but not solved. In other words, the problem now became what to charge the affiliated entity for use of that common resource. And that problem involves precisely the same difficulties of allocation that is fundamental to the issue in the first place.

But suppose we set up a set of groundrules, something like this:

- whatever service is provided by one affiliate to the other must also be made available, at the same price and under the same conditions, to everyone else, and furthermore

- there cannot be any restrictions on how that purchaser can use the facilities he's obtained. In other words, we apply a rule of unlimited resale and sharing.

Let me suggest that this relatively simple set of ground-rules can change the situation radically. It does so by letting the marketplace provide the penalties for cross-subsidization rather than relying on fine-grain surveillance by the regulators.

What happens in this simple scheme when the provider of facilities -- who uses part of these facilities for providing so-called monopoly services and sells part to all comers -- tries to cross-subsidize? If he tries to subsidize the ones he sells, he subsidizes the World. He subsidizes his own competitors who can now use the very facilities they obtain from him to configure services that will undercut his own services. If he overprices the facilities, he hurts his own affiliate, which is trying to compete against firm who can choose between building their own, buying facilities from the affiliate, or buying them from someone else.

To be sure, this is an oversimplification. But with refinements, I think it is quite possible to substitute some marketplace forces for some regulation. A perfectly logical step, since regulation is, in the first place, only a substitute for marketplace forces.

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Another way to change the regulatory scheme would be for the regulator to abandon the attempt to control cost/price relationships for every service and every service element, and to concentrate instead on preventing flows of subsidies from one broad category of services to another. For example he might concentrate, as I believe the bills in Congress do, on preventing cross-subsidy from MTS, WATS, and Exchange to all other services.

Such a step would simplify the problem enormously, since it would eliminate the need for many of the extremely fine-grain data that are now required. It would also shift the responsibility of proper pricing to the management, where it belongs. As Don Redmond has pointed out, there's more to pricing than costs, especially for the more competitive services.

<u>Let's Put it All Together Now</u>:

We now have three building blocks:

- we can disaggregate some of the common resources, thereby reducing the size and complexity of the problem

- we can set up some new organizational frameworks separating services between which we want to avoid flows of cross-subsidies; we thereby convert internal transactions into inter-company ones, thus making them more visible and easier to deal with, and

- we can change the regulatory scheme somewhat -- (1) by letting the marketplace do some of the work, through new rules for non-discriminatory availability of facilities to affiliates and non-affiliates alike, coupled with unlimited resale and sharing, and (2) by having the Commission set up new rules which would concentrate on controlling cross subsidy flows between groups of services rather than on a service-by-service or element-by-element basis.

I think you will recognize that recent FCC dockets, as well as proposed legislation, make use of all three of these building blocks.

They set up separate subsidiaries, with restrictions on various ways of using resources in common. They provide for unlimited resale and sharing, and non-discriminatory access. And, there is at least some hope that with these changes they will relax some of the now unnecessary very fine-grain surveillance. As for the latter, I tend to be a bit pessimistic -- but we'll see.

<u>What About Accounting, Then?</u>

As we've seen the USOA proposal tries to solve the cross-subsidy problem by brute force -- by fine-grain cost accounting and allocational schemes. It's a tough way to solve the problem.

Now, what happens if you set up separate subsidiaries for the competitive services, and promulgate a set of rules that will let the marketplace do some of the job?

I don't know what <u>will</u> happen, but let me suggest what could and should happen.

You might quit worrying about cross-subsidies flowing <u>within</u> a subsidiary -- or rather, let the management worry about that -- and concentrate on two types of transactions:

(1) inter-affiliate transactions, and

(2) a special case of (1), the internal costs of functions that one affiliate performs for another.

I would suggest to you, first, that that's all that's needed to prevent real cross-subsidization, and two, that an accounting system to do those two jobs is an order of magnitude or two <u>easier to design</u> than the proposed revision of the USOA.

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USE OF THE REVISED SYSTEM OF ACCOUNTS FOR PRICING PURPOSES

Donald Andrew Redman
Vice President - Measurements and Budgets
General Telephone and Electronics Corporation

INTRODUCTION

The telecommunications industry is undergoing rapid and significant change on almost every front. Some of the most significant technological changes in the areas of micro-circuitry, bubble memory and laser technology bear directly upon the telecommunications industry. The market structure of the industry continues to undergo fundamental change. These, along with other changes, have altered the meaning and application of existing regulatory and legislative ground rules and have stimulated widespread debate over the need for a revised Uniform System of Accounts and a definitive framework for pricing and costing telecommunications products and services.

Consumer advocates and special interest groups are bringing increasing pressure to bear on utilities, regulators and government on such issues as market behavior, rate structures, patterns of subsidization, use of resources and so on. In the midst of this turmoil, we find telecommunications utilities trying to make rational pricing and marketing decisions without adequate information and analytical tools, and we find regulators trying to fulfill their public duty to regulate these utilities in a national way, but they too have inadequate information and analytical tools for the tasks that lie ahead.

In addressing our topic today, Use of the Revised System of Accounts for Pricing Purposes, I will try to avoid conjecture about the future of deregulation and probable changes in market structure except to note that there will continue to be changes, and we will cope with these as they unfold. Also, I will try to avoid the temptation to address the relevance of regulation in a competitive environment. What I am going to do is to present a perspective through which changes in the Uniform System of Accounts can be structured and effectively finalized, implemented and which when completed, will provide valid costing input into the pricing process without extensive changes in the nature or scope of the existing financial accounting structure.

I plan to approach our subject today by first discussing the pricing process to identify the relevant inputs and tracking mechanisms that would be desirable from a cost accounting system. Then we will move into a brief discussion of the proposed revisions to the USOA in light of these desirable characteristics and will finish up with an overall perspective for supporting changes to the USOA.

Before beginning, I would like to identify some common states of nature and regulatory constraints that exist now and will probably continue to exist for the foreseeable future that will provide the focus for our discussion and which have an important bearing on the relationship between accounting and the pricing process:

(a) Utilities now serve both competitive and noncompetitive monopoly markets - both of which are fully subject to regulation.

(b) Utilities are subject to two different regulatory jurisdictions, state and interstate, and each jurisdiction requires separate rate hearings and permits separate rates of return.

(c) Utilities incur costs that are common to both its competitive and monopoly operation and have costs which are common to its operations in different jurisdictions.

(d) A utility's aggregate operations in each regulatory jurisdiction is subject to a rate of return constraint. This constraint acts as a ceiling on prices and revenues in the aggregate.

(e) A utility's competitive operations must produce compensatory results, so that the utility's monopoly services are not burdened by its competitive services. This constraint acts as a floor on the utility's competitive operations.

(f) Regulation desires some kind of "meaningful" relationship between prices and costs in the interest of fairness and economic efficiency and over which it can exercise regulatory oversight.

(g) It should be recognized that pricing and costing are separate but inseparable. Each interacts upon and affects the other. At the same time, it should be recognized that they are two completely different processes measuring different things in different ways for different purposes.

PRICING PROCESS FOR REGULATED UTILITIES

Let's spend a moment to explore the interaction between cost accounting as envisioned under the proposed changes to the USOA and the present price setting process of a rate hearing to identify what contribution or additional inputs the revision to the USOA may provide that are not available today.

In general terms, the process of monitoring and setting rates begins with an analysis of information from three sources:

1. The Uniform System of Accounts, (where we are now).

2. General business, economic and industry trends and forecasts, (if we stay on the same course, what will the future look like?).

3. Stakeholder objectives, (where do we want to be?).

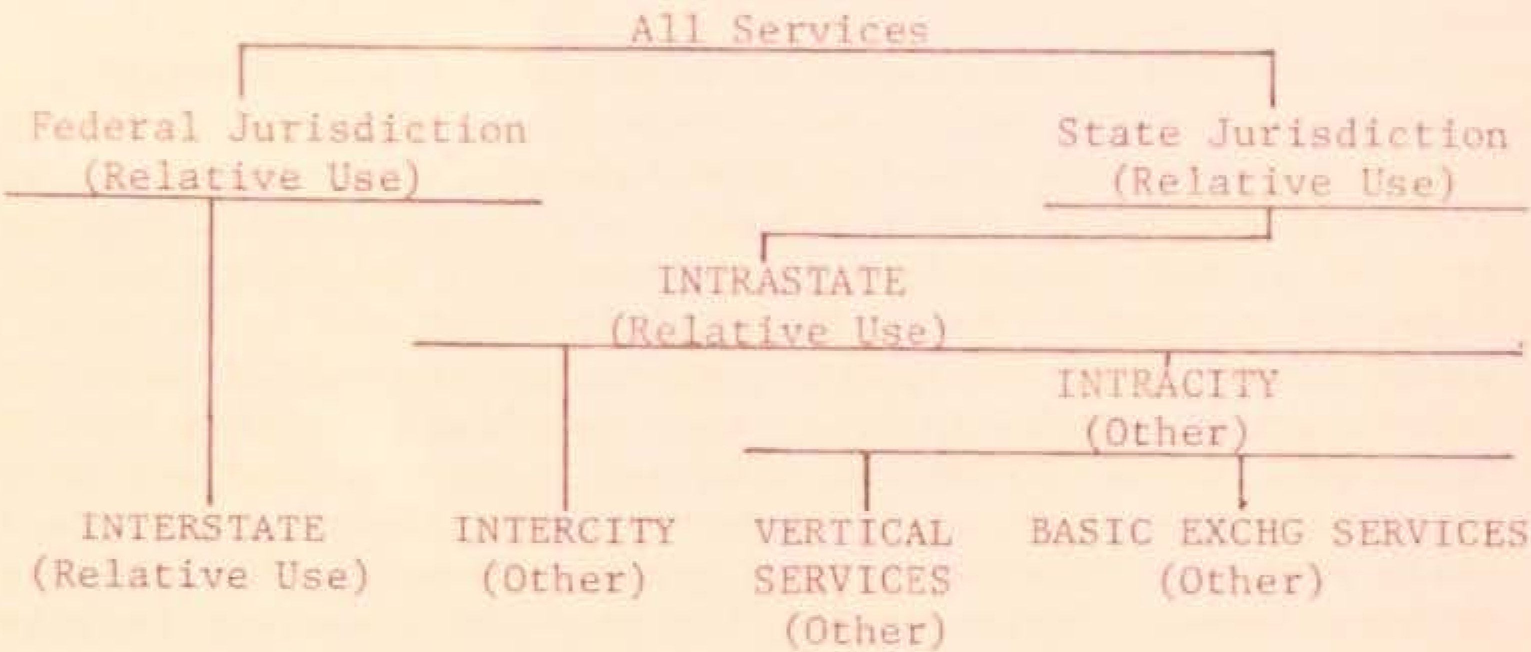
As gaps develop between where we are and where we want to be in terms of an equitable rate of return; even though management has done all it can to reduce costs, generate additional revenues, improve productivity and scale back programs; the process of preparing a general rate hearing is set into motion.

Preparation of the rate hearing begins with the development of an Aggregate Revenue Requirement based upon historical book costs, as identified in the Uniform System of Accounts for a given "test period." The revenue requirement represents the Total Revenue to be generated to cover Expenses, Taxes and a Return for invested capital. It is actually the reverse of the accounting process and is a bottoms-up approach starting with Expenses plus Return and Taxes to arrive at Total Revenue Required. This approach considers all costs of the firm and is in effect a fully allocated costing approach which sets a ceiling constraint on aggregate prices via an earnings limitation.

Once the Aggregate Revenue Requirement is determined and the ceiling constraint on earnings is known, it then becomes necessary to determine specifically how this revenue will be generated, i.e., how much should be charged for each product or service offered within each appropriate jurisdiction.

Historically, this process involves the jurisdictional separation of costs which is accomplished using the concept of "relative use." Under this concept, all costs of the firm are separated along jurisdictional lines between Interstate Services (which are essentially interstate toll calling) and Intrastate Services. The Intrastate Services are further segregated, again based on "relative usage," between Intercity Services (which are essentially state toll calling) and Intracity Services. Intracity Services are further segregated between Vertical/ Discretionary Services (competitive) and Basic Exchange Services (monopoly).

To diagram this segregation, it would look like the following:



Throughout this entire separations process, keep in mind that it is being done in conformance with established separations procedures and within the context of the 1934 Federal Communications Act, which established "Universal Service" as the primary goal of our national telecommunications policy.

The first objective of our national policy is to provide affordable, high-quality, two-way communication capability to virtually every residence and business in the country. The key element of this objective is its "affordability" and setting rates for these services that are affordable led to the "value of service" rate setting concept and nationwide averaging for the Interstate Segment.

I have identified four segments or four semi-aggregate revenue requirement levels - Interstate, Intercity, Vertical Services and Basic Exchange Services - that in the aggregate are the ceiling constraints to be used in determining specifically how much should be charged for each product or service offered. For Vertical Services the revenue requirement when based on attributable costs, represents the floor constraint.

You should also note that each revenue requirement segment includes fully allocated costs - complete with taxes, expenses and return. From this, it then follows that the general body of users of each of the four segments of products and services are going to be charged for the costs that are incurred by the firm in providing that segment of service and underlying those costs are "relative use." The degree of which each segment absorbs or contributes to the recovery of overheads is the variable that has given rise to the question of cross subsidization.

Constrained as a supplier of last resort with prices to be set at affordable rates under the Universal Service Legislative Mandate and with the introduction of competition, multi-dimensional incongruencies emerge.

Number one is the issue of separating costs based on "relative usage." Some have argued that costs should be assigned or separated based upon the principle of "cost causation" with each segment viewed independently, which would shift the assignment of certain costs from the Interstate, Intercity and Vertical Services segment to Basic Exchange Services and in so doing, would reduce rates charged for these services while substantially increasing the rates to be charged for Basic Exchange Services. Remember, however, that the national telecommunications policy established in 1934, was to provide "affordable" service and Basic Exchange Services as the major segment of what they were talking about. It is essentially your local monthly telephone bill or the cost just to participate in the network.

The second issue is how the separated revenue requirement, regardless of whether it is separated based upon cost causation or relative usage, should be generated in terms of setting specific rates for each tariff offering.

Historically, different approaches have been used for the various segments. Individual tariffs for the Interstate Segment, under the jurisdiction of the FCC, have generally been determined based upon national averages of costs associated with time or usage and distance. This has resulted in uniform national rates from point-to-point without regard for specific differences in each telephone company's operations, equipment or density of calling volume from point-to-point.

Tariffs for Intrastate Intercity Services have been determined in much the same way except under the jurisdiction of the state commissions.

Regarding the Intracity or Vertical and Basic Exchange Services, also under the jurisdiction of the state commissions, tariffed rates are determined using an incremental costing approach in conjunction with demand forecasts for competitive services and a residual revenue requirement approach tempered with value of service concepts, usage and cost causer principles for monopoly services depending upon the particular service or item of equipment offered.

After respective jurisdictional authorities review and modify the rates, if deemed in the public interest, the particular tariff rates are approved and implemented.

Again, it has been argued by some that in setting specific tariffed rates, the "cost causer" principle should be exclusively followed. On its face, such an argument sounds like a reasonable and plausible alternative. However, we have come to learn that what it really means is that any cost incurred by the firm should be assigned or in some way, allocated or prorated to a specific service and that such costs would become the primary basis for establishing rates.

In summary, it means deaveraging our rates based exclusively on cost and taken to its extreme, for example, could mean that a customer living next door to one of our central offices would pay $5 per month for local telephone service, while his neighbor down the street would pay $5.50 and so on until the elderly person living out his lean retirement years on a one acre homestead 20 miles from our central office would pay $102 per month. Then, in addition, each customer would pay for usage according to the specific trunk route used, the distance involved and so forth on each call. Such an approach doesn't seem practical and would appear to be contradictory with the National Telecommunication Policy of "affordable" service for all.

An analogy would be if the state charged you a flat amount each month as an access charge for the road running in front of your house to your place of employment, and then charged you a usage fee for each mile driven within the city for the month.

If you traveled between towns, the Federal Authorities would charge you an access charge plus an amount per mile with different rates per mile depending upon which road you traveled. Then, when you got to the town you were going to, the state again, would charge you an access charge to the city plus a rate per mile for each of the different roads you traveled there.

By the way, this idea has been suggested to Congress as one way to reduce fuel consumption and stimulate energy conservation. Variations in rates have been argued for cost causation associated with different sizes of vehicles, their origin of manufacture, fuel consumption, style and color. The suggestion has the full support of the benefactors of such a program on the basis that it would stimulate technological innovation, improve productivity, reduce unemployment and contribute to the reduction of inflationary pressures.

There has been opposition from the losers - smaller towns and villages between and around the larger cities and from the small independent road builders, who fear that bike lanes and bicycles will become the new renaissance of the 80's.

All joking aside, we really don't see that happening - but I do want to emphasize the interactive complexities and the regulatory/industry consensus that needs to evolve as we move forward through this transition regulated competitive period. This is the beginning of the Electronic Information Age, and we think one of the most important and exciting "new beginnings" for the communications industry.

The entire rate hearing process, which begins with the historically recorded financial transactions of the company and ends with approved tariff rates, has other complexities that deserve mentioning.

The rate hearing process often requires a year or longer to complete. This time dimension creates pricing inflexibility in the competitive market place and increases the business risks associated with all segments of our business without any corresponding reward.

As you know, from an Accounting perspective, as expenses increase without corresponding rate adjustments, recovery is lost forever. This finds its ultimate reflection in the financial deterioration of the firm, and in the short run, results in an increased cost of capital.

Another complexity is the lack of a tracking system. After rating decisions have been made, complete with all the inherent assumptions about the future on specific service offerings, the existing USOA and including the associated record keeping requirements as prescribed by the FCC, does not provide a framework for monitoring or tracking the results or decision assumptions and the corresponding cost experiences subsequently incurred for each tariff offering. In essence then, telephone companies have no prescribed management accounting system for determining or tracking costs for each tariff offering.

The existing USOA is a Financial Accounting System designed and intended for use in meeting external reporting requirements and to satisfy regulatory overview prescriptions.

The most important and perhaps significant complexity surfacing to date that I alluded to earlier was the idea that rate setting should be based exclusively on historical costs for a given "test period."

The rate ceiling contraints, i.e., the revenue requirement, for each business segment is fully cost compensatory based on relative usage. The rates set for specific products and services within that business segment are not based on fully distributed costs, not because we are lacking a prescribed system of accounts for determining fully distributed costs, but because rates for specific products and services is not and should not be solely predicated upon costs - regardless of how costs are defined whether that cost is fully distributed, incremental, direct, variable, assignable, proratable, based on relative usage or based on actual cost causation.

It would be difficult to imagine, for example, that a repair shop would price a replacement fender based strictly on test period historical cost plus a percentage for profit equivalent to their overall rate of return.

The point being is that rate setting is a function of the market place rather than an exclusive function of cost. There are other valid and relevant approaches for determining rates that should be considered and "cost plus" based upon test period historical fully distributed highly aggregated costs is only one possibility, and one that does not function well in a competitive market.

It is extremely important that rate setting policies and objectives be considered first because the methods or approaches to rate determination are only a means to an end - the objectives. Generally, rate setting policies and objectives will flow from the regulators for State and Interstate Toll and Basic Exchange Services (monopoly) and from top management for Vertical/Discretionary Services (Competitive).

At this juncture, the rate setting objective for Toll and Basic Exchange Service is a "Target Return on Invesment," while the pricing objective for Vertical/Discretionary Services is "Profit Maximization" over the long-run, as reflected in the market place. Each of these objectives requires different analytical tools and different costing information.

The revenue requirement approach using fully distributed costs would appear to be an adequate analytical tool for determining rates under the "Target Rate of Return" objective provided an adequate level of costing detail exists for setting rates for broad groupings of services and a tracking mechanism is available.

Regarding "Profit Maximization" objectives, the appropriate analytical tool would be a Long-Run Incremental Cost Analysis that is dependent upon demand forecasts and direct incremental costs.

PROPOSED REVISION TO THE USOA

I would now like to examine with you the proposed changes to the USOA and come to some conclusions about how they might contribute in some meaningful way to the rate setting process.

We, at GTE, support certain revisions to the USOA and feel that the proposed revisions are a good "first cut" that provides the basis for identifying some of the real problems and which indicate areas where more soul-searching is going to be required. However, as evidenced by the recent FCC De-Tariffing Order in Docket 18128, and the effort currently underway in Docket 79-245 to develop and prescribe specific procedures for allocating costs to services, and since the proposed changes to the USOA seem to preclude the use of more than one costing methodology - it would be logical to conclude that the parameters and framework of the telecommunications industry should first stablize before proceeding with revisions to the USOA. This does not mean that the development of a Management Information System should be held in abeyance, however.

What it does suggest is that a Cost or Managerial Accounting System and a Financial Accounting System such as the USOA are two distinctly different but interdependent systems and are only two of many sub-systems that will make up a much larger Management Information System.

An important segment of the Management Information System obviously would include Regulatory Information requirements along with a considerable amount of other information that is required by Management in the day-to-day operations of business.

It also suggests that the present structure of the USOA, along technological and functional lines, is adequate. Adequate in the sense that the basic principles of classifying financial transactions in terms of their technological or functional nature are as sound today as they were in 1935.

In general terms, it appears the proposed changes to the USOA are more the result of frustration in dealing with complex business problems without adequate "costing and operating" information than with specific problems associated with the USOA and its underlying principles. The existing USOA updated for the new technological innovations and expanded to handle new functional activity such as direct sales, leasing, and Generally Accepted Accounting Principles, seems to be the essence of revisions that should be made to the USOA.

This approach in recognizing that financial accounting and cost accounting are separate but inseparable in much the same way that pricing and costing are separate but inseparable and by retaining the underlying principles associated with the USOA, would ensure the stability, integrity and flexibility that are needed and absolutely essential to satisfy the many external reporting requirements that exist today for large publicly held corporations that depend heavily upon externally generated funds to support the rapidly changing markets with new technological innovations.

I can imagine that each of you are sitting there thinking - "Well, Don has suggested that costing and rate setting are two different things and that they can not be inextricably linked, and now he is suggesting that financial accounting and cost accounting are two different things and that they too can not be inextricably linked - I know I need to move towards cost-sensitive/cost-based rates, and those costs should be those costs reflected in my financial systems - What then is the answer, and where do we go from here?"

We obviously don't have as many of the answers as we would like, but as I mentioned at the beginning, my purpose is to add a perspective through which changes in the USOA and in Cost Accounting can be structured to contribute to a solution to this dilemma.

You will note that the focus or center of the dilemma is Cost Accounting or I prefer to call it Managerial Accounting:

$$\begin{tikzcd} \text{Financial Accounting} \arrow[rr, bend left, <->] & \text{Cost} \arrow[l] \arrow[r] & \text{Rate Setting Methodology} \arrow[ll, bend left, <->] \end{tikzcd}$$

and the key point is that it can not be inextricably linked with either financial accounting or the rate setting process but which must function as a source of input and/or be reconcilable with numerous financial reporting requirements and a multitude of pricing methodologies and techniques that are still being developed and are evolving for the telecommunications industry.

Of the variables we have to work with, known and unknown, what are they and were do we stand:

A. Financial reporting requirements are well-established.

B. Rate setting methodologies and techniques, although probably well-established in the competitive market place, are really just beginning to be developed and are evolving for the telecommunications industry.

C. Cost accounting methodologies and techniques, although generally well-established in nonservice related industries, are just beginning to be developed and are evolving for the telecommunications industry.

Financial reporting requirements are well understood and need no further elaboration here.

We have already talked about the rate setting process and concluded that it is a market-driven function especially for competitive service offerings and sensitized by public convenience and necessity for monopoly services offered.

What about Cost Accounting? There are a couple of principles in Real Estate Brokerage that I would like to modify and use for Cost Accounting that will help put it into its proper perspective: the Real Estate principles are:

A. Under All is the Land

B. The Value of Land is in Relationship to its Highest and Best Use.

For Cost Accounting we can modify them as follows:

A. Under All is the Functional Activity and Physical Attributes of Resources
(costing and cost allocations are a bottoms-up process).

B. Cost Information has Value Only in Relationship to its Highest and Best Use
(time period, hierarchical structure or level of aggregation, questions asked).

The practical application of the first principle would indicate that cost accounting begins at a base level, the beginning of a process, the lowest practical level that can be identified in terms of the functional activities performed and the physical attributes of resources consumed in an operation.

The second principle indicates that information about the cost of something has value and meaning only in relationship to something else and in how it is going to be used or the question it is trying to answer.

Let's see how this would work. In your minds, if you will, visualize a two dimensional chart where in one section you have identified all the relevant functions and physical attributes and in the other section you have identified a hierarchical structure of your products and services.

This hierarchical structure of products and services is in effect a pyramid and at the bottom are all of your individual products and services. Further up the pyramid, the individual products and services are aggregated into product lines, product groups, market segments, then markets and finally at the peak general administration.

This provides a structure where we can take all of the functional activity, cost them for a given accounting period and relate them in an economically meaningful way in terms of cost causation to the firm's hierarchial structure of products and services.

At the bottom of the pyramid, are the functional activities and associated costs that can be attributed directly to the individual products and services. These are costs directly related to the production of specific tariffed outputs.

For example, for a specific PABX product, such as GTE's GTD-120 PABX, these would include costs related to the purchase and installation of GTD-120 PABX equipment, maintenance of such equipment, record keeping on such equipment, direct costs of selling systems to customers and so forth.

At the top of the pyramid are functional activities and associated costs that are related only in an aggregate way to the total operation. These are costs related to the general administration of the business as opposed to the production of its outputs. Included in this area would be such things as the cost of filing reports with the Securities and Exchange Commission, determining compliance standards for EEO and reviewing new federal or state regulations to assess their applicability to the firm's operation.

Functional activities and related cost associated with the levels in between the top and bottom of this hierarchical structure represent costs which are overheads from the point of view of individual products and services but which can be directly attributable only to various groups or aggregations of individual products and services.

For example, we can have some costs which are directly attributable to the utility's Voice Product Line Segment but which can not be directly attributable to any specific product in that segment. Such costs might include market research to identify and evaluate new features customers would like to have on any of the Voice products.

We can see from the structure of such a pyramid that the level at which a given cost appears in the pyramid is a function of the scope of the company's business to which the cost can be directly attributable.

What we have then is a hierarchy of costs that essentially consist of direct costs at the bottom of the pyramid and various levels of overhead costs.

The overhead costs are separately identifiable, associated on a cost causation basis, and directly attributable to:

A. Groupings or aggregations of individual products and Services and,

B. General administration of the business.

This facilitates the development of contribution margins based upon relevant costs for any specific product or service and for any level of aggregation of products and services such as product lines, product groups, market segments and total markets.

It also leaves intact and identifiable the general administrative expenses of the business that must be recovered equitably from the contribution margins provided by the various markets in which the utility operates.

Such a structure provides a rational approach in providing flexibility in costing analysis, rate setting analysis, decision making and regulatory oversight. Flexible in the sense that we now have costs that are based upon a bottoms-up approach, i.e., functionally based economic relationships that can be used to address different questions for different purposes. Flexible also in the sense that they are reconcilable and useful within the rate setting process and within the Financial Accounting System because they are functionally based rather than arbitrarily derived from a top down allocation process of contrived relationships to effect the allocation of all costs downward to specific products and services.

And last, but not least, it will provide a tracking mechanism and feedback loop for monitoring cost assumptions that are included in the rate setting process.

CONCLUSION

To conclude my presentation and before opening it up for discussion, let me summarize the major points:

I. Rate setting is a function of the market place for competitive services and sensitized by the public interest for monopoly services. Rate setting and its relationship to cost is only one of many variables that enter into the rate setting process. The most significant of these are the relevant costs, the costs that are directly attributable at the level of aggregation under analysis. Such costs need to be separately identified and reconcilable with the rate setting process and the USOA.

II. Financial Accounting and Managerial Accounting are two separate but inseparable processes much like rate setting and costing that can not be inextricably linked but which must be reconcilable. This can be accomplished by relating functional activity with a hierarchical structure of products and services.

III. At the center of the costing/rate setting/USOA dilemma is the lack of a standard costing system rather than in the basic principles underlying the existing USOA or in the rate setting processes per se.

A. Development of a functionally based, standards driven costing system should precede, in terms of priority, changes to the USOA, and should move in concert with the development of various rate setting approaches as the telecommunications market structure evolves.

B. Such a system should facilitate a contribution analysis at any level of aggregation and provide a tracking mechanism for monitoring cost behavior assumptions implicit in futuristic rate setting decisions.

TWENTY-FIFTH SESSION, Friday, May 23 - 10:15 a.m.

Concurrent Session J-3

ADDED THOUGHTS ON THE PROPER RATE OF RETURN FOR ECONOMY STUDIES

CHAIRMAN: Gerald W. Smith, Ph.D.
Professor of Industrial Engineering
Iowa State University

SPEAKERS: George E. Lamp, Jr., Ph.D.
Associate Professor of Industrial Engineering
Iowa State University

Kenneth R. Meyer, Senior Financial Consultant
Energy Development Section
Wells Fargo Bank

SETS OF ASSUMPTIONS UPON WHICH THE COMPOSITE COST OF CAPITAL AND THE TAX ADJUSTED COST OF CAPITAL MAY BE BASED

George E. Lamp, Jr., Ph.D.
Iowa State University

INTRODUCTION

The subject of which discount rate to use in an economic analysis, the composite cost of capital or the tax adjusted cost of capital, has generated some controversy over the years [1,2,3,4]. The formula for calculating the annual equivalent before tax cash flow (AEBTCF) using the composite cost of capital is not the same as the formula for calculating the AEBTCF using the tax adjusted cost of capital. The AEBTCF is the annual equivalent of the dollars required to (1) pay the income taxes each year associated with a return on a capital investment, (2) pay the return required on the unrecovered capital each year, and (3) repay (recover) the first cost of the investment over the life of the investment in some fashion. If both the debt ratio and the effective income tax rate are greater than zero and the net salvage is not equal to the first cost, then these two formulas give different results.

One possible explanation of why there are two different formulas (which yield different results) may be because each formula could be based on a different set of assumptions. Four sets of assumptions are presented in the third and fourth sections of this paper (two sets for each formula). Each of these sets of assumptions and the corresponding formula are "consistent" in a special sense-the year by year analysis of the AEBTCF (according to the assumptions) shows that the AEBTCF is just sufficient to pay income taxes each year, pay the return required on the unrecovered capital each year and repay (recover) the invested capital over the life of the project. If a formula and a set of assumptions are consistent then the assumptions could be the basis for the formula.

There could be, of course, other sets of assumptions with which a formula is "consistent" in one sense or another.

The next section presents a set of common assumptions intended to eliminate other areas of controversy that might arise in an engineering economy analysis. The third section of this paper presents two sets of assumptions with which the tax adjusted cost of capital is consistent. An example is used to illustrate the year by year analysis (according to each assumption set) of the AEBTCF obtained from the tax adjusted cost of capital formula.

Next, two sets of assumptions with which the composite cost of capital formula is consistent are presented. The essential differences between each composite cost of capital assumption set and the somewhat analogous tax adjusted cost of capital assumption set is pointed out. The example mentioned above is used to illustrate the year by year analysis of the AEBTCF (obtained from the composite cost of capital formula) in accordance with each set of assumptions.

The next section contains comments about the material in the preceding sections. Finally, some additional sets of assumptions dealing with the idea of repaying capital first (rather than paying the return required on capital first) are discussed.

The mathematical proof of the consistency of a formula and a set of assumptions is somewhat lengthy. The derivation of the tax adjusted cost of capital in a manner consistent with assumptions set A, is provided by Smith [5]. The general equations for the mathematical proofs of the consistency of the other sets of assumptions and the corresponding formula are given in Appendix B. More complete proofs may be obtained from the author.

COMMON ASSUMPTIONS

The purpose of this paper is to look at only the composite cost of capital, tax adjusted cost of capital controversy. Therefore a number of assumptions are made to eliminate other potential areas of controversy. These assumptions are common to both formulas. For a given ("real life") situation, a decision as to whether to make any or all of these assumptions would probably not depend upon the selection of a particular formula.

The common assumptions are [6]:

1. The how, when, etc. of the replacement of retired property is irrelevant to the analysis.

2. The uses that could be made of funds returned by a project (the repayment of capital) are irrelevant to the analysis.

3. The following parameters are single valued and known with certainty: first cost, salvage value, life.

4. The following parameters are single valued, known with certainty, and do not vary over time: effective tax rate, rate of return required on debt, rate of return required on equity, debt ratio, equity ratio.

5. Debt and equity are the only sources of capital.

6. The first cost is invested at the beginning of the first year and all other cash flows occur at the end of the year.

7. Compounding of "interest" is done annually at the end of the year.

8. Investment tax credit is zero.

9. The entire first cost less net salvage value is depreciable for both book and tax purposes.

10. The treatment of net salvage value is the same for both book and tax purposes.

11. The life is the same for both book and tax purposes.

12. Income taxes due each year are paid in full each year.

13. The problems of "flow through" and "normalization" (for book purposes) of certain tax items are ignored.

14. Item accounting is used for depreciation purposes.

15. The after tax cash flow (ATCF) is completely utilized in paying the required return on capital and the repayment of capital.

16. If the taxable income from the project under consideration is negative in any year, the company has sufficient revenues from other projects to enable the project under study to realize a tax savings. The tax savings is computed as: (the tax rate) (negative taxable income).

In addition, cash operating costs are excluded from the analysis.

An important assumption which perhaps needs emphasis is one part of #4, above - the debt ratio and equity ratio must be kept constant.

TAX ADJUSTED COST OF CAPITAL

The formula for the AEBTCF using the tax adjusted cost of capital is [5]:

$$\text{AEBTCF} = [B(A/P,i_a,n) - V(A/F,i_a,n) - t\,(\text{AED})] \,/(1-t)$$

= annual equivalent of the before tax cash flow

= revenues - cash operating expenses

B = first cost

$(A/P,i_a,n)$ = the "annuity from a present worth" factor

i_a = tax adjusted cost of capital

$= i_d r_d + i_e r_e - t r_d i_d$

n = life of project

i_d = interest rate on debt

r_d = debt ratio

= (debt)/(debt + equity)

i_e = rate of return on equity

r_e = equity ratio

= (equity)/(debt + equity)

t = effective tax rate on taxable income

V = net salvage value

$(A/F,i_a,n)$ = the "annuity from a future worth" factor

AED = the annual equivalent of the tax depreciation

One set of assumptions, say set A, with which the above formula is consistent is [6]:

1. "The taxable income for a year is computed as the AEBTCF minus (1) interest on the actual unrecovered debt at the beginning of the year and (2) the tax depreciation for the year.

2. The after tax cash flow (ATCF) for a year is the AEBTCF minus the income taxes for the year calculated according to assumption 1.

3. The return required on the unrecovered book capital (both debt and equity) at the beginning of the year is deducted first from the ATCF for the year.

4. The ATCF remaining after deduction of the required return on capital is used to repay capital (r_d of the remainder is used to repay debt capital and r_e of the remainder is used to repay equity capital)."

The following data are used in the examples throughout this paper:

$B = \$24{,}000$ $\qquad i_d = 12\%$

$V = \$\ 3{,}000$ $\qquad r_d = 55\%$

$n = 3$ years $\qquad i_e = 17\%$

$t = 0.4$ $\qquad r_e = 45\%$

straight line depreciation for tax purposes

Then

$$i_c = (0.12)\ (0.55) + (0.17)\ (0.45)$$

$$= 0.1425$$

$$i_a = (0.12)\ (0.55) + (0.17)\ (0.45) - 0.4\ (0.12)\ (0.55)$$

$$= 0.1161$$

The AEBTCF by the tax adjusted cost of capital formula is:

$$\text{AEBTCF} = [24{,}000\ (A/P,\ 11.61\%,\ 3) - 3000\ (A/F,\ 11.61\%,\ 3) - 0.4\ \left(\frac{24{,}000 - 3000}{3}\right)]\ /(1-0.4)$$

$$= \$10{,}388.49$$

Table I, Appendix A, is the year by year analysis of the AEBTCF in accordance with assumption set A. As can be observed, the AEBTCF is just sufficient to pay the income taxes each year, pay the return required on the unrecovered book capital each year and repay the capital over the life of the project. Although straight line depreciation was used for tax purposes, any method of tax depreciation could have been used (different methods will yield different AED's and, thus, different AEBTCF's).

One may wish to specify a specific schedule for the repayment of (book) capital. Assumption set B is another set of assumptions with which the tax adjusted cost of capital formula is consistent; set B provides a specified repayment (of book capital) schedule [6]:

1. "The taxable income for a year is computed as the AEBTCF minus (1) interest on the actual unrecovered "initial" debt at the beginning of the year and (2) the tax depreciation for the year.

2. The ATCF is the AEBTCF minus the income taxes for the year calculated according to assumption 1.

3. The return required on the unrecovered, "initial" book capital (i.e., the unrecovered portion of the $24,000) at the beginning of the year is deducted first from the ATCF for the year.

4. The repayment of capital for book purposes is according to some specified schedule.

5. Any deficiency (or excess) arising from the repayment of capital for book purposes being greater (or lesser) than the ATCF minus return on capital is met by obtaining (or repaying) "new" capital (keeping the debt ratio, the interest rate required on debt and the rate of return required on equity constant).

6. Interest on the "new" debt is deductible for tax purposes.

7. Since the "new" capital is not invested in depreciable property, there is no depreciation associated with the "new" capital.

8. Any deficiency in funds arising from paying the yearly returns on "new" capital is met by obtaining additional "new" capital (keeping the debt ratio, the interest rate required on debt and the rate of return required on equity constant)."

Since the same formula is used for set B as was used for set A, the AEBTCF is $10,388.49, the same as before. Assume the book capital is to be repaid by the following schedule: $7,000., $7,000., $10,000. This is "straight line depreciation" plus salvage at the end of the third year.

Table II, Appendix A, is the year by year analysis and it shows that the AEBTCF is just sufficient to pay the income taxes each year, pay the return required on the unrecovered capital each year and repay the capital over the life of the project in the specified manner. Although straight line depreciation was used for both tax depreciation and book recovery of capital in the example, tax depreciation and the book recovery schedule need not be the same and neither needs to be straight line.

Perhaps a small example would illustrate why a "deficiency" may arise when an annual equivalent amount is calculated. Assume you have borrowed $2000. at 10%. The debt is to be repaid in equal installments at the end of each of the next two years plus interest on the unrepaid amount.

That is:

$$\text{payment at end of year 1} = \$1000 + (0.1)(2000) = \$1200$$

$$\text{payment at end of year 2} = \$1000 + (0.1)(1000) = \$1100$$

The annual equivalent of these two payments is

$$\text{annual equivalent payment} = [1200\ (P/F, 10\%, 1) + 1100\ (P/F, 10\%, 2)]\ (A/P, 10\%, 2) = \$1152.3809$$

If we assume the dollars available for a payment to the lender at the end of the first year is equal to the annual equivalent payment, \$1152.3809, then the dollars available are not sufficient to make the necessary first year's payment of \$1200. One possible solution for the borrower is to borrow enough more from some source, at 10% interest, to make up the deficiency of:

$$\text{deficiency} = \$1200 - 1152.3809 = \$47.6191$$

By borrowing \$47.6191 from some source, you (the borrower) are able to make the required \$1200 payment. At the beginning of the second year, you owe \$1000 + \$47.6191 or a total of \$1047.6191. The interest due at the end of year two on this amount is \$104.7619. Therefore the total payment required at the end of the second year to pay interest on both the old and new debt and to repay both the old and the new debt is:

$$\text{payment} = \$104.7619 + 1000 + 47.6191 = \$1152.3810$$

which is (almost) exactly the amount of the annual equivalent payment, \$1152.3809.

In Table II, the interest on any "new" debt is deductible for tax purposes; the resulting "tax savings" reduces the total amount of "new" capital that would otherwise be needed.

COMPOSITE COST OF CAPITAL

The formula for the AEBTCF using the composite cost of capital is [7]:

$$\text{AEBTCF} = B\ (A/P, i_c, n) - V\ (A/F, i_c, n) + \emptyset\ [B(A/P, i_c, n) - V(A/F\ i_c, n) - \text{AED}]$$

B,V,N,AED, i_d, r_d, i_e, r_e are the same as before. The "A/P" and "A/F" factors are the same as before except i_c rather than i_a is the appropriate discount rate.

$$i_c = i_d r_d + i_e r_e$$

$$\phi = \left(\frac{t}{1-t}\right)\left(1-\frac{r_d i_d}{i_c}\right)$$

One set of assumptions, say set C, with which this formula is consistent is [6]:

1. "The taxable income for a year is computed as the AEBTCF minus (1) interest on the amount of debt that would be unrecovered if the repayment of capital each year was equal to tax depreciation for the year and (2) the tax depreciation for the year.

2. The ATCF for a year is the AEBTCF minus the income taxes for the year calculated according to assumption 1.

3. The return required on the unrecovered book capital (both debt and equity) at the beginning of the year is deducted first from the ATCF for the year.

4. The ATCF remaining after deduction of the required return on capital is used to repay capital (r_d of the remainder is used to repay debt capital and r_e of the remainder is used to repay equity capital).

Set C is quite similar to set A. The difference between the two sets is in assumption #1 of both sets. In A, the tax deductible interest is based on the unrecovered book debt; in C, the tax deductible interest is based on the debt that would be unrecovered if capital were repaid according to the tax depreciation schedule.

The AEBTCF for the example is:

$$\begin{aligned}\text{AEBTCF} &= 24{,}000\ (A/P,\ 14.25\%,\ 3) - 3000\ (A/F,\ 14.25\%,\ 3)\\ &\quad+\left[\frac{0.4}{1-0.4}\right]\left[1-\frac{(0.55)(0.12)}{0.1425}\right]\ [24{,}000\ (A/P,\ 14.25\%,3)\\ &\quad- 3000\ (A/F,\ 14.25\%,\ 3) - \left(\frac{24{,}000-3000}{3}\right)]\\ &= \$10{,}409.44\end{aligned}$$

Table III, Appendix A, presents the year by year analysis of the AEBTCF in accordance with assumption set C. This analysis shows that the AEBTCF is just sufficient to pay the income taxes each year, pay the return on the unrecovered book capital each year and repay the capital over the life of the project. Thus the formula and assumption set C are consistent.

Another set of assumptions, say set D, with which the composite cost of capital formula is consistent is [6]:

1. "The taxable income for a year is computed as the AEBTCF minus (1) interest on the amount of the "initial" debt that would be unrecovered if the repayment of capital each year was equal to tax depreciation for the year and (2) the tax depreciation for the year.

2. The ATCF is the AEBTCF minus the income taxes for the year calculated according to assumption 1.

3. The return required on the unrecovered, "initial" book capital (i.e., the unrecovered portion of the $24,000) at the beginning of the year is deducted first from the ATCF for the year.

4. The repayment of capital for book purposes is according to some specified schedule.

5. Any deficiency (or excess) arising from the repayment of capital (for book purposes) being greater (or lesser) than the ATCF minus return on capital is met by obtaining (or repaying) "new" capital (keeping the debt ratio, the interest rate required on debt and the rate of return required on equity constant).

6. Interest on the "new" debt is not deductible for tax purposes.

7. Since the "new" capital is not invested in depreciable property, there is no depreciation associated with the "new" capital.

8. Any deficiency in funds arising from paying the yearly returns on "new" capital is met by obtaining additional "new" capital (keeping the debt ratio, the interest rate required on debt and the rate of return required on equity constant)."

Assumptions sets B and D are quite similar. The difference between the two sets is in assumptions #1 and #6 of both sets. In set B, the amount of the tax deductible interest on debt is the interest on the total unrecovered book debt, i.e., both initial debt and "new" debt. This can be seen by looking at lines (16), (17), and (18) of Table II. The net dollars needed for interest required on new debt, (18), is the interest rate times the amount of "new" debt, (16), reduced by the tax savings, (17), because of the tax deductibility of interest on debt. In set D, the amount of debt utilized in computing tax deductible interest is the amount of the "initial" debt that would be unrecovered if capital were repaid according to the tax depreciation schedule; the interest on "new" debt is not deductible for tax purposes.

Since the composite cost of capital formula is the same as for set C, the AEBTCF is $10,409.44. Table IV, Appendix A, is the year by year analysis of the AEBTCF in the manner specified by assumption set D. As can be seen, the AEBTCF is just sufficient to pay the income taxes each year, pay the interest required on the unrecovered capital each year and repay the capital over the life of the project in the specified manner.

COMMENTS

A formula and a set of assumptions were said to be "consistent" if the AEBTCF was just sufficient to pay the income taxes each year, pay the return required on the unrecovered capital each year and repay the capital over the life of the project in the manner indicated in the assumptions. All four sets of assumptions and the corresponding formulas are consistent in this sense.

Other sets of assumptions with which these formulas are consistent in one sense or another are possible.

"Consistency" does not imply a formula is acceptable. Whether a formula is acceptable or not should be determined by an evaluation of the assumptions upon which the formula is based.

Although the example used straight line depreciation for tax purposes and for capital recovery (in sets B and D), any depreciation method and capital repayment schedule, if appropriate, can be used and they need not be the same.

Finally, for assumption sets B and D, all of the "after tax cash flow" should be utilized to pay the return on unrecovered capital and to repay capital. None of these assumption sets and the corresponding formula are really equipped to deal with "excess" funds which would, probably, be invested in something and earning a taxable return until such time as they might be needed to pay the return required on unrecovered capital and/or to repay capital.

ADDITIONAL SETS OF ASSUMPTIONS

Discussions with some individuals have raised the problem of what to do if the repayment of capital rather than the return on capital is deducted first from the ATCF.

A set of assumptions, say set E, for the tax adjusted cost of capital approach which provides for this is:

1. The taxable income for a year is computed as the AEBTCF minus (1)interest on the actual unrecovered debt at the beginning of the year and (2) the tax depreciation for the year.
2. The ATCF for a year is the AEBTCF minus the income taxes for the year calculated according to assumption 1.
3. The repayment of capital for book purposes (according to some specified schedule) is deducted first from the ATCF.
4. The ATCF remaining after repaying capital is used to pay the return required on the unrecovered book capital (both debt and equity) at the beginning of the year.
5. Any deficiency (or excess) of the ATCF in repaying capital and paying the return required on capital remains a deficiency (or if an excess, used to pay off the deficiency) which earns at an effective compound discount rate equal to i_a until the deficiency and the accumulated return thereon is repaid.

Table V, Appendix A is the year by year analysis of the AEBTCF and it shows that the AEBTCF is just sufficient to pay the income tax each year, repay the capital each year according to the specified schedule, pay the return required and repay any deficiencies over the life of the project.

Although assumption 5 does not specify how much of the deficiency is debt and how much is equity, nor what the required discount rate should be on each of these, the effective discount rate must be equal to i_a. One "reasonable" choice might be to treat r_d of the deficiency as debt with a required discount rate of i_d and r_e of the deficiency as equity with a required discount rate of i_e; also, the interest on the debt portion of the debt is tax deductible and the effective income tax rate is kept constant at t. Now note that many of the rows of Table V are the same as certain rows in Table II. In particular:

	Table V	Table II
Row	(15)	(14)
Row	(16)	(21)
Row	(17)	(22)

Thus, Table V seems to be a shortened version of Table II, which it is.

Another set of assumptions, say set F, which also embodies the idea of repaying capital first is identical to assumption set B except for the following

3. The repayment of capital for book purposes (according to some specified schedule) is deducted first from the ATCF for the year.

4. The return required on the unrecovered initial book capital is then paid.

5. Any deficiency (or excess) arising from the ATCF being greater (or lesser) than the repayment of capital and the return required on capital is met by obtaining (or repaying) new capital (keeping the debt ratio, the interest rate required on debt and rate of return required on equity constant).

Since both the repayment of capital and the payment of return required on capital are paid in full each year, the year by year calculations and the mathematical proof that the formula and assumption set F are consistent are the same as for set B.

Two parallel assumption sets could be easily established for the composite cost of capital approach. These sets would yield year by year analyses which are shortened or similar versions of Table IV for assumption set D.

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APPENDIX A

Table I. The Year By Year Analysis of the AEBTCF
Based on Assumption A

		Year 1	Year 2	Year 3
(1)	AEBTCF	10,388.49	10,388.49	10,388.49
(2)	-Interest on debt (12%)	1,584.00	1,171.72	711.57
(3)	-Tax depreciation	7,000.00	7,000.00	7,000.00
(4)	Taxable income	1,804.49	2,216.77	2,676.92
(5)	Income Tax (40%)	721.80	886.71	1,070.77
(6)	ATCF	9,666.69	9,501.78	12,317.72*
(7)	Unrecovered debt, Jan. 1	13,200	9,764.32	5,929.76
(8)	Interest required on debt (12%)	1,584	1,171.72	711.57
(9)	Unrecovered equity, Jan. 1	10,800	7,988.99	4,851.62
(10)	Return required on equity (17%)	1,836	1,358.13	824.77
(11)	Available for repayment of capital	6,246.69	6,971.93	10,781.38
(12)	Repayment of debt (0.55)	3,435.68	3,834.56	5,929.76
(13)	Repayment of equity (0.45)	2,811.01	3,137.37	4,851.62

* includes salvage of $3000

$(2)_j = (8)_j = 0.12 * (7)_j$

$(3)_j = (24{,}000-3000)/3$

$(4)_j = (1)_j - (2)_j - (3)_j$

$(5)_j = 0.4 * (4)_j$

$(6)_j = (1)_j - (5)_j$

$(7)_1 = 0.55 * (24{,}000)$

$(7)_{j+1} = (7)_j - (12)_j$

$(9)_1 = 0.45 * (24000)$

$(9)_{j+1} = (9)_j - (13)_j$

$(10)_j = 0.17 * (9)_j$

$(11)_j = (6)_j - (8)_j - (10)_j$

$(12)_j = 0.55 * (11)_j$

$(13)_j = 0.45 * (11)_j$

Table II. The Year by Year Analysis of the AEBTCF Based on Assumption Set B

		Year 1	Year 2	Year 3
(1)	AEBTCF	$10,388.49	$10,388.49	$10,388.49
(2)	-Interest on debt (12%)	1,584.	1,122.	660.
(3)	-Tax depreciation	7,000.	7,000.	7,000.
(4)	Taxable income	1,804.49	2,266.49	2,728.49
(5)	Income tax (40%)	721.80	906.60	1,091.40
(6)	ATCF	9,666.69	9,481.89	12,297.09*
(7)	Unrecovered debt, Jan. 1	13,200.	9,350.	5,500
(8)	Interest required on debt (12%)	1,584.	1,122	660
(9)	Unrecovered equity, Jan. 1	10,800	7,650	4,500
(10)	Return required on equity (17%)	1,836	1,300.50	765.
(11)	Available for repayment of capital	6,246.69	7,059.39	10,872.09
(12)	Repayment of debt	3,850.	3,850.	5,500. **
(13)	Repayment of equity	3,150.	3,150.	4,500. **
(14)	Excess (deficiency) for repayment of capital from ATCF	(753.31)	59.39	872.09
(15)	Total "new" debt, Jan. 1	0	414.32	429.76***
(16)	Interest required on "new" debt (12%)	0	49.72	51.57
(17)	-Tax savings on interest on "new" debt	0	19.89	20.63
(18)	Net $'s required for interest on "new" debt	0	29.83	30.94
(19)	Total new equity, Jan. 1	0	338.99	351.62
(20)	Return required on "new" equity (17%)	0	57.63	59.78
(21)	Total return requirements for "new" capital (deficiency)	0	(87.46)	(90.72)
(22)	Total excess (deficiency) for the year	(753.31)	(28.07)	781.37
(23)	Additional "new" debt needed (0.55)	414.32	15.44	(429.75)***
(24)	Additional "new" equity needed (0.45)	338.99	12.63	(351.62)

*includes salvage of $3000

**includes an appropriate amount of salvage

***the difference between the unrecovered "new" debt. Jan. 1 of the third year, $429.76, and the repayment of "new" debt at the end of the third year, $429.75, is due to rounding.

Table II cont.

(2), (3), (4), (5), (6) as before

$(7)_1 = 0.55 * (24,000)$

$(7)_{j+1} = (7)_j - (12)_j$

$(8)_j = 0.12 * (7)_j$

$(9)_1 = 0.45 * (24,000)$

$(9)_{j+1} = (9)_j - (13)_j$

$(10)_j = 0.17 * (9)_j$

$(11)_j = (6)_j - (8)_j - (10)_j$

$(12)_1 = (12)_2 = 0.55\ (7,000)$

$(12)_3 = 0.55\ (7,000) + 0.55\ (3,000)$

$(13)_1 = (13)_2 = 0.45\ (7,000)$

$(13)_2 = 0.45\ (7,000) + 0.45\ (3,000)$

$(14)_j = (11)_j - (12)_j - (13)_j$

$(15)_1 = 0$

$(15)_{j+1} = (15)_j + (23)_j$

$(16)_j = 0.12 * (15)_j$

$(17)_j = 0.4 * (16)_j$

$(18)_j = (16)_j - (17)_j$

$(19)_1 = 0$

$(19)_{j+1} = (19)_j + (24)_j$

$(20)_j = 0.17 * (19)_j$

$(21)_j = (18)_j + (20)_j$

$(22)_j = (14)_j + (21)_j$

$(23)_j = 0.55 * (22)_j$

$(24)_j = 0.45 * (22)_j$

Table III. The Year by Year Analysis of the AEBTCF Based on Assumption Set C

		Year		
		1	2	3
(1)	AEBTCF	$10,409.44	$10,409.44	$10,409.44
(2)	"Unrecovered" debt Jan. 1 if capital were repayed according to tax depr.	13,200.	9,350.	5,500.
(3)	-Interest on "unrecovered" debt (12%)	1,584.	1,122.	660.
(4)	-Tax depreciation	7,000.	7,000.	7,000.
(5)	Taxable income	1,825.44	2,287.84	2,749.44
(6)	Income Tax (40%)	730.18	914.98	1,099.78
(7)	ATCF	9,679.26	9,494.46	12,309.66*
(8)	Unrecovered book debt, Jan. 1	13,200.	9,757.41	5,925.89**
(9)	Interest required on unrecovered book debt (12%)	1,584.	1,170.89	711.11
(10)	Unrecovered equity, Jan. 1	10,800.	7,983.33	4,848.45**
(11)	Return required on equity (17%)	1,836.	1,357.17	824.24
(12)	Available for repayment of capital	6,259.26	6,966.40	10,774.31
(13)	Repayment of debt (0.55)	3,442.59	3,831.52	5,925.87**
(14)	Repayment of equity (0.45)	2,816.67	3,134.88	4,848.44**

*includes salvage of $3000

**differences due to rounding

$(2)_1 = 0.55\ (24{,}000)$

$(2)_{j+1} = (2)_j - 0.55 * (4)_j$

$(3)_j = 0.12 * (2)_j$

$(4)_j = (24{,}000 - 3000)/3$

$(5)_j = (1)_j - (3)_j - (4)_j$

$(6)_j = 0.4 * (5)_j$

$(7)_j = (1)_j - (6)_j$

$(8)_1 = 0.55 * (24{,}000)$

$(8)_{j+1} = (8)_j - (13)_j$

$(9)_j = 0.12 * (8)_j$

$(10)_1 = 0.45 * (24000)$

$(10)_{j+1} = (10)_j - (14)_j$

$(11)_j = 0.17 * (10)_j$

$(12)_j = (7)_j - (9)_j - (11)_j$

$(13)_j = 0.55 * (12)_j$

$(14)_j = 0.45 * (12)_j$

Table IV. The Year by Year Analysis of the AEBTCF Based on Assumption Set D

		Year 1	Year 2	Year 3
(1)	AEBTCF	10,409.44	10,409.44	10,409.44
(2)	"Unrecovered" debt Jan. 1 if capital were repaid according to tax depr.	13,200	9,350.	5,500.
(3)	-Interest on debt (12%)	1,584	1,122.	660.
(4)	-Tax depreciation	7,000	7,000.	7,000.
(5)	Taxable income	1,825.44	2,287.44	2,749.44
(6)	Income tax (40%)	730.18	914.98	1,099.78
(7)	ATCF	9,679.26	9,494.46	12,309.66*
(8)	Unrecovered book debt, Jan. 1	13,200	9,350.	5,500.
(9)	Interest required on debt, (12%)	1,584.	1,122.	660.
(10)	Unrecovered equity, Jan. 1	10,800	7,650	4,500
(11)	Return required on equity (17%)	1,836.	1,300.50	765.
(12)	Available for the repayment of capital	6,259.26	7,071.96	10,884.66
(13)	Repayment of book debt	3,850.	3,850.	5,500. **
(14)	Repayment of equity	3,150	3,150	4,500 **
(15)	Excess (deficiency) for repayment of capital from ATCF	(740.74)	71.96	884.66
(16)	Total "new" debt, Jan. 1	0	407.41	425.89***
(17)	Interest required on "new" debt (12%)	0	48.89	51.11
(18)	Total "new" equity, Jan. 1	0	333.33	348.45***
(19)	Return required on "new" equity (17%)	0	56.67	59.24
(20)	Total return requirements for "new" capital (deficiency)	0	(105.56)	(110.35)
(21)	Total excess (deficiency) for the year	(740.74)	(33.60)	774.31
(22)	Additional "new" debt needed (0.55)	407.41	18.48	(425.87)***
(23)	Additional "new" equity needed (0.45)	333.33	15.12	(348.44)***

*includes salvage of $3000
**includes appropriate amount of salvage
***differences are due to rounding

Table IV. continued

$(2)_1 = 0.55\ (24{,}000)$

$(2)_{j+1} = (2)_j - 0.55\ (7000)$ straight line tax depreciation = \$7000/year

$(3)_j = 0.12 * (2)_j$

$(4)_j = (24{,}000-3000)/3$

$(5)_j = (1)_j - (3)_j - (4)_j$

$(6)_j = 0.4 * (5)_j$

$(7)_j = (1)_j - (6)_j$

$(8)_1 = 0.55 * (24{,}000)$

$(8)_{j+1} = (8)_j - 0.55\ (7000)$ straight line book recovery = \$7000/years

$(9)_j = 0.12 * (8)_j$

$(10)_1 = 0.45\ (24{,}000)$

$(10)_{j+1} = (10)_j - 0.45\ (7000)$ straight line book recovery = \$7000/year

$(11)_j = 0.17 * (10)_j$

$(12)_j = (7)_j - (9)_j - (11)_j$

$(13)_j = 0.55 * (7000)$ straight line book recovery = \$7000/year

$(14)_j = 0.45 * (7000)$ straight line book recovery = \$7000/year

$(15)_j = (12)_j - (13)_j - (14)_j$

$(16)_1 = 0$

$(16)_{j+1} = (16)_j + (22)_j$

$(17)_j = 0.12 * (16)_j$

$(18)_1 = 0$

$(18)_{j+1} = (18)_j + (23)_j$

$(19)_j = 0.17 * (18)_j$

$(20)_j = (17)_j + (19)_j$

$(21)_j = (15)_j + (20)_j$

$(22)_j = 0.55 * (21)_j$

$(23)_j = 0.45 * (21)_j$

Table V. The Year By Year Analysis of the AEBTCF Based on Assumption Set E

		1	2	3
(1)	AEBTCF	10,388.49	10,388.49	10,388.49
(2)	-Interest on debt	1,584.	1,122.	660.
(3)	-Tax depreciation	7,000.	7,000	7,000
(4)	Taxable income	1,804.49	2,266.49	2,728.49
(5)	Income tax	721.80	906.60	1,091.40
(6)	ATCF	9,666.69	9,481.89	12,297.09*
(7)	Unrecovered debt 1-1	13,200.	9,350.	5,500
(8)	Recovery of debt	3,850	3,850	5,500
(9)	Unrecovered equity, 1-1	10,800	7,650.	4,500
(10)	Recovery of equity	3,150	3,150	4,500
(11)	Available for return required on debt & equity	2,666.69	2,481.89	2,297.09
(12)	Return required on debt	1,584.	1,122.	660.
(13)	Return required on equity	1,836.	1,300.50	765.
(14)	Total return required	3,420.	2,422.50	1,425.
(15)	Excess (deficiency) in funds available for return required on debt & equity	(753.31)	59.39	872.09
(16)	Return required on deficiency, 1-1, 11.61%	0	(87.46)	(90.72)
(17)	Total excess (deficiency) for the year	(753.31)	(28.07)	781.37
(18)	Accumulated deficiency, 12-31	(753.31)	(781.38)	(0.01)**

*includes net salvage
**due to rounding

$(2)_j = (12)_j = 0.12 * (7)_j$

$(3)_j = (24{,}000-3000)/3=7000$

$(4)_j = (1)_j - (2)_j - (3)_j$

$(5)_j = 0.4 * (4)_j$

$(6)_j = (1)_j - (5)_j$

$(7)_1 = 0.55 * 24{,}000$

$(7)_{j+1} = (7)_j - (8)_j$

$(8)_1 = (8)_2 = 0.55 * 7000$

$(8)_3 = 0.55 * 7000 + 0.55 * 3000$

$(9)_1 = 0.45 * 24{,}000$

$(9)_{j+1} = (9)_j - (10)_j$

$(10)_1 = (10)_2 = 0.45 * 7000$

$(10)_3 = 0.45 * 7000 + 0.45 * 3000$

$(11)_j = (6)_j - (8)_j - (10)_j$

$(12)_j = 0.12 * (7)_j$

$(13)_j = 0.17 * (9)_j$

$(14)_j = (12)_j + (13)_j$

$(15)_j = (11)_j - (14)_j$

$(16)_{j+1} = 0.1161 * (18)_j$

$(17)_j = (15)_j + (16)_j$

$(18)_j = (18)_{j-1} + (17)_j$

APPENDIX B

I. The general equations for the mathematical proof that assumption set B (and also, set E) and the tax adjusted cost of capital formula are consistent are [6]:

"new" capital required in a year = book recovery of "initial" capital for the year - (after tax cash flow for the year - return on the unrecovered "initial" book capital at the beginning of the year) + (return on any unrecovered "new" capital at the beginning of the year - tax savings on the interest portion of the return on "new" capital).

Let

D_x = tax depreciation for year x

D'_x = recovery of "initial" book capital for year x

H_x = amount of "new" capital needed at end of year x

B_x = unrecovered book capital at end of year x

Then

$$H_1 = D'_1 - (ATCF_1 - i_c B)$$

$$H_2 = D'_2 - (ATCF_2 - i_c B_1) + i_a H_1$$

$$H_j = D'_j - (ATCF_j - i_c B_{j-1}) + i_a (H_1 + H_2 + --- + H_{j-1})$$

$$H_n = D'_n - (ATCF_n - i_c B_{n-1}) + i_a (H_1 + H_2 + --- + H_{n-1})$$

Also

$$ATCF_j = AEBTCF - t(AEBTCF - D_j - i_d r_d B_{j-1})$$

$$B_{j-1} = B - D'_1 - D'_2 - --- - D'_{j-1}$$

If the assumption set and the formula are to be consistent, then

$$H_1 + H_2 + --- + H_n = 0$$

II. The general equations for the mathematical proof that assumption set C and the composite cost of capital formula are consistent are [6].

recovery of book capital in a year = after cash flow - return on unrecovered book capital at the beginning of the year.

Let

D_j = tax depreciation for year j

F_j = return of book capital in year j

Then

$$F_1 = ATCF_1 - i_c\ B$$

$$F_2 = ATCF_2 - i_c\ (B-F_1)$$

$$F_j = ATCF_j - i_c(B-F_1 - F_2 - \text{---} - F_{j-1})$$

$$F_n = ATCF_n - i_c\ (B-F_1 - F_2 - \text{---} - F_{n-1}) + V$$

Also

$$ATCF_j = AEBTCF - t[AEBTCF-D_j - i_d r_d\ (B-D_1 - D_2 - \text{---} - D_{j-1})]$$

If the assumption set and the formula are to be consistent, then

$$F_1 + F_2 + \text{---} + F_n = B$$

III. The general equations for the mathematical proof that assumption set D and the composite cost of capital formula are consistent are [6]:

"new" capital required in a year = book recovery of "initial" capital for the year - (after tax cash flow for the year - return on the unrecovered "initial" book capital at the beginning of the year) + return on any unrecovered "new" capital at the beginning of the year

Let

D_x = tax depreciation for year x

D'_x = recovery of "initial" book capital in year x

G_x = amount of "new" capital needed at end of year x

B_x = unrecovered amount of "initial" book capital at end of year x

Then

$$G_1 = D'_1 - (ATCF_1 - i_c\ B)$$

$$G_2 = D'_2 - (ATCF_2 - i_c B_1) + i_c\ G_1$$

$$G_j = D'_j - (ATCF_j - i_c B_{j-1}) + i_c\ (G_1 + G_2 + \text{---} + G_{j-1})$$

$$G_n = D'_n - (ATCF_n - i_c B_{n-1}) + i_c\ (G_1 + G_2 + \text{---} + G_{n-1})$$

Also

$$ATCF_j = AEBTCF - t\ [AEBTCF - D_j - i_d r_d (B-D_1 - D_2 - \text{---} - D_{j-1})]$$

$$B_{j-1} = B - D'_1 - D'_2 - \text{---} - D'_{j-1}$$

If the assumption set and the AEBTCF formula are to be consistent then:

$$G_1 + G_2 + \text{---} + G_n = 0$$

UTILITY INVESTMENT PLANNING:
The Importance of The Discount Rate

Kenneth R. Meyer
Energy Development Section
Corporate Finance Department
Wells Fargo Bank, N.A.
San Francisco, California

"Those who devote themselves to practice without science are like sailors who put to sea without rudder or compass and who can never be certain where they are going. Practice must always be based on sound theory."--Leonardo Da Vinci

BACKGROUND

The methodology used to analyze public utility investment decisions has been a controversial subject for more than twenty-two years. For many years the controversy centered on the proper method for computing the correct discount rate used to convert a series of annual costs to a single value appropriate for economic comparison.

Previous papers (1 and 2) have established the validity of using a discount rate adjusted for the tax deductibility of interest expense (Table 1) for determining the equivalent cost of a project to the utility. The discount rate controversy now has evolved to an examination of the correctness of the assumptions and procedures used to establish the validity of the tax adjusted discount rate and the broader issue of the overall objectives of utility investment analysis.

The discount rate is the focal point for understanding the theory and practice of the economics and operations of a company. The discount rate mirrors the basic structure of a firm's operating environment and its financing policies. The discount rate helps describe the dynamics of the firm. A clear understanding of the discount rate by utility managers is absolutely necessary for the concise communication of the firm's objectives and for the managers to direct the firm on a course which satisfies the expectations of investors.

Table 1

	1 Percent of Total Capital	2 Cost	3 Before Tax Discount Rate	4 Tax Reduction at 50%	5 Tax Adjusted Discount Rate
Debt	40%	10%	4%	2%	2%
Equity	60%	15%	9%		9%
			13%		11%

PURPOSE

The purpose of this paper is to clarify the decision process of utility executives and those performing investment analysis by carefully examining the role of the discount rate. To accomplish this objective, the paper is divided into the following sections:

I. PUBLIC UTILITY INVESTMENT ANALYSIS

--Review

II. BASIC ECONOMIC ISSUES:

--Perspectives of Utilities, Individuals, and Society

III. APPLICATIONS OF THE UTILITY TAX ADJUSTED DISCOUNT RATE

--Nuclear Decommissioning Cost Recovery
--Marginal Costs of Electricity

IV. UTILITY CAPITAL COST RECOVERY ASSUMPTIONS

--Rates versus Economic Analysis

V. CONCLUSIONS

I. PUBLIC UTILITY INVESTMENT ANALYSIS (2)

Utility managers are confronted with a multitude of investment decisions due to the capital intensive nature of the industry. The analysis of a major project begins with a set of assumptions about general economic conditions (Figure 1). The assumptions are used to forecast annual capital and operating costs for each project. These costs are computed for each year of a project's life, in accordance with regulations and accounting rules. These annual costs also equal the annual revenue requirements from customers. The annual costs are converted to equivalent annual figures to facilitate comparison with other projects by using a discount rate.

The discount rate is used as a weighting factor in economic analysis. It takes into account the time value of money. Because costs are compounded at some interest rate more weight is given to costs incurred in early years.

The present value of a project's annual costs equals the total cost of a project in today's dollars. The difference in the present values of two alternative projects equals the present value of cumulative savings of one project over the alternative. The difference in the levelized cost of two projects equals the anticipated annual cost savings. The levelized cost is determined by multiplying the present value of a project's cost by the annuity factor for the time period over which the total cost of the project is to be recovered.

The cost curves in Figure 2 illustrate the role of the discount rate in utility economic analysis. The cost savings attained by the coal plant in the early years are financially equivalent to the cost savings attained by the nuclear plant in the latter years with a discount rate of twelve percent. In other words, the levelized costs and the present values of the two projects are equal. A larger discount rate would make the coal plant less costly since each year's savings would be divided by an exponentially larger number.

The economic model used in utility investment analysis is the discounted cash flow model. The discounted cash flows of utility investments are equal to the original cost of the investment. Hence, the net present value of all utility projects equals zero. This condition implies that investors have been fairly compensated for the risks incurred. Utility investment analysis assumes that regulators will adjust rates so that the company will recover the costs associated with a project in a manner financially equivalent to the costs incurred. When this occurs, the revenues obtained from customers are just sufficient to cover the costs of the investment.

With the net present value of all projects equal to zero, the investment decision objective for a utility becomes cost minimization. The project which has the least discounted cost is the economic choice. The least cost project for customers depends on their discount rate for utility services. If it equals the company's rate, then the utility's economic choice is the same as the customer's.

The economic analysis of investment alternatives provides the manager with a ranking of projects in terms of increasing expected cost to the utility. Final project selection requires human judgment. The manager must decide whether the subjective factors associated with a decision are sufficient to compensate for the differences in cost. The economic analysis is an aid to judgment since it enables the manager to place the subjective factors in the terms of expected cost differences.

II. BASIC ECONOMIC ISSUES

The purpose of this section is to focus on the significance of the annual cost curves depicted in Figure 2 from the perspective of the utility, individuals, and society.

Each curve represents the total costs incurred by the utility to operate a plant on an annual basis. The total costs are equal to the capital costs plus the operating expenses which are dominated by the fuel costs. The annual costs decrease in the early years since debt and equity investors' return is earned on a decreasing amount of unrecovered capital. The capital costs (debt and equity return, taxes, debt and equity capital recovery) decrease annually to zero at the end of the useful life. However, fuel costs increase exponentially with time due to expected escalation and soon completely offset the decreasing capital costs. Thus, fuel costs dominate the total costs in later years. It should be noted that in constant dollars the annual costs decrease exponentially with an adjustment for inflation (Figure 2a). In real terms costs may actually decrease in each year depending on the inflation rate and the percentage of fixed to total costs.

The magnitude and shape of the curves are determined by the regulatory environment in which the utility operates. For example, a change from normalization to flow-through accounting of accelerated tax depreciation benefits would shift the recovery of capital costs (taxes) to later years. The magnitude of the curves would increase as investors perceive a decrease in the protection of their capital. This increased risk translates to higher required debt and equity returns and taxes, thus increasing the relative magnitude of the curves. The costs to the utility, individuals, and society are increased with the cost burden shifted to future generations.

With this background we are prepared to examine the question of the investment and regulatory preferences of the utility, individuals, and society. Which decisions are preferable: 1) A capital intensive plant with lower operating costs or a plant with higher operating costs and lower capital costs? 2) The normalization or flow-through accounting of tax benefits? The discount rate is a key to answering these questions.

In Figure 1 the decision objective for the utility is the least cost to the utility. Costs (present value or levelized) were determined on the basis of equivalent cost to the utility. Knowing the levelized equivalent cost to the utility is important, because this value informs society of the price the utility must charge in terms of a uniform annual rate to completely recover project costs. The annual cost curves, which are determined by regulations and accounting rules, are important since they inform society of the changing cost of electricity as a function of time. The present value of the annual costs give us cost information at the point in time with which we are the most familar and thus able to make the best comparisons--the present. This information is useful since individuals, corporations, and society must budget their limited resources for essential services such as water and electricity. For example, a corporation which produces an electricity intensive product for which there are substitutes knows that sales and profits are dependent on relative production costs.

Once the utility knows the relative ranking of the alternatives in terms of equivalent costs, a number of subjective factors are considered, among these, the viewpoints of individuals and society.

Most individuals do not have the same discount rate for electricity as the utility. Estimates for the discount rate for individuals range from the 6% interest rate on insured savings to the 18% interest rate on credit cards. When an individual budgets the last dollar of income, the following alternatives are considered: paying a higher utility bill now is compared with these two forms of increased savings. However, an inflationary environment which encourages consumption does not lead one to think too seriously about savings. For example, my discount rate for utility services is at least 50%. The choice is between a higher bill today or the purchase of a fishing rod on sale--50% off. The fish caught on vacation with this improved equipment will make me more happy and productive. The purchase is easily rationalized knowing that I will probably have more money in the future to pay the higher bill (smaller fraction of my budget) and the payment can be made with cheaper, inflated dollars. Besides, utility services are essential and, therefore, should always be as close to free as possible. The fact that consumer debt is at record high levels and savings rates are at record lows provides good confirmation of this kind of individual reasoning.

Of course, many individuals view the investment alternatives with a more conservative perspective. Utility executives fall in this category when they view the decision from the standpoint of society. For a society to prosper, the demands and requirements of future generations must be considered. For example, most of us want our children to have access to the natural beauty of our national parks and those resources which are essential to an increasing quality of life. This attitude is reflected in the use of small or even negative discount rates for the analysis of some investments. Another example of this attitude is provided by capital intensive investments, such as home insulation which lasts generations and allows our children to allocate more income to recreation and learning.

When the subjective factors are considered, the spectrum of discount rates to be used by utility managers expands far beyond the present controversy. The emphasis shifts from a small range of values to knowing what the numbers mean and the consequences associated with the decision to use a particular value. However, at least two discount rates are important to all of us. Just as we all want to know the interest factor on our house mortgage to compute the annual payments, we should want to know the expected equivalent annual or present value of electricity rates for the purpose of planning our individual, corporate, and national budgets. The tax-adjusted discount rate is used to determine these values. Secondly, the discount rate which equates the two areas between the curves in Figure 2 is important. This discount rate, in the case of the selection of a more capital intensive project, tells us the rate at which we are being forced to save money. We pay higher electricity rates now with the expectation of lower rates in the future. In essence, we are saving money via the utility cost recovery mechanisms which are established by state and federal laws and regulatory commissions. Therefore, the cost of electricity is not only determined by which project is selected, but also by 1) government agencies and laws which specify the rules by which costs are recovered, 2) the certainty of recovery, and 3) the capital structure of the utility. All three of these are risk and return considerations which are approved and/or promulgated by utility commissions.

III. APPLICATIONS OF THE TAX ADJUSTED UTILITY DISCOUNT RATE

Previous discussions concerning discount rates have primarily centered on the proper use of a discount rate in the investment analysis process. Recent events, however, are forcing attention to the role of the discount rate in determining the future price of electricity. The need for the establishment of cost recovery procedures for the eventual decommissioning of nuclear plants was brought into sharp focus by the events at Three Mile Island. Conservative wisdom reasons that these costs, like the costs associated with nuclear fuel disposal, should be recovered over the useful life of the asset. Since the cost is a forward cost, the discount rate is central to comparing the desirability of alternatives and the consequences of various cost recovery methods. The uncertainty of approach due to the lack of agreement or understanding of a utility discount rate (described as "chaotic" by V. L. Schwent--3--) can be eliminated once the meaning of equivalent cost is perceived by analysts. A detailed analysis of this question is beyond the scope of this paper. However, one of the many approaches to the problem is presented in example 2.

A more significant and encompassing issue concerning equivalent utility cost has developed as a result of the Public Utility Regulatory Policies Act of 1978 (PURPA). One provision of PURPA requires state utility commissions to permit utilities to contract for the purchase of power from small power producers who are exempted from regulation. To qualify for exemption, the price paid for the power is limited by the utility's marginal cost. The detailed implementation of this provision is the responsibility of each state commission but must conform to legislative intent.

The objective of the following comments is to briefly examine the role and importance of the discount rate in determining a utility's marginal costs.

Suppose a utility or a forest products company wants to determine the potential amount of economically feasible small power projects using forest and mill waste products. Plant capital and operating costs are well known. The cost of obtaining the fuel, gathering, and transportation are uncertain and are determined to be the controlling factors on the supply side.

The annual cost curves in Figure 2 do not provide a good economic indicator of marginal cost since early years are allocated a disproportionate share of lifetime capital costs due to accounting conventions. The levelized equivalent total annual costs using the discount rate overcomes this problem thus providing a better indicator of marginal costs. The utility and its customers are economically indifferent to building the avoided plant or paying wood waste power producers the marginal cost of the avoided plant. With this information a boundary can be placed on wood fuel costs. The amount of economically feasible projects thus can be estimated.

Another example of the importance of the discount rate is in the determination of economically feasible energy conservation devices. For example, the Pacific Gas and Electric Company will finance interest free certain conservation improvements including ceiling, floor, and wall insulation, weather-stripping, caulking, etc., which produce cumulative savings greater than the cost of new energy resources (reference 4).

The discount rate used to levelize the utility plant costs is an important factor in determining the supply of energy derived from alternative energy sources. In many regions of the country the marginal units displaced by small power producers or conservation measures utilize oil. Hence, the utility discount rate directly affects our nation's dependence on foreign oil.

The levelization of plant total costs provides a necessary and convenient method for comparing the overall economics of alternative investments. However, as a practical matter, the levelized total cost is not the marginal cost society pays since rates are determined in accordance with regulations and accounting conventions.

A change from a levelized payment approach to an actual annual cost schedule using the coal plant example (Figure 2) would increase the first year's payment by 26%. This payment schedule would have the following benefits: 1) consistent with actual marginal costs, 2) increase alternative energy development since higher payments would be made in early years, 3) the resulting investments would reduce foreign oil dependence, 4) correspond to the actual cash requirements of small power producers since their costs are also recovered in accordance with similar accounting conventions, and 5) facilitate project financing.

IV. UTILITY CAPITAL COST RECOVERY

The primary obstacle in the acceptance of the validity of using the tax adjusted discount rate to determine equivalent utility costs appears to be the assumption dealing with the theory and practice of the capital recovery assumption. Tables E1 through E4 (2) define the nature of the problem.

A comparison of the Tables E3 and E4 reveals that in period 1 revenues, taxes, and the amount of investor principal recovered change. The revenues were changed by design, levelization made them smaller in the first period and larger in the second. Taxes changed in the same manner. The tax laws were not changed; tax depreciation remains the same. Debt and equity return assumptions were satisfied. Although the returns are larger in the second period, so is the amount of investor capital outstanding. Book depreciation changes. Book depreciation equals the rate of recovery of investor capital. However, Table E5 (2) demonstrates that investors are indifferent to this change since their return expectations are still satisfied. In fact, the rate of book depreciation does not change the present value of the costs of a project. A change in tax depreciation, however, does effect the present value and levelized costs. The levelized costs also change if the number of years over which the costs are recovered changes. An increase in the number of years simply decreases the relative annual costs. It does not change the "economics" of the project from the viewpoint of investors since their expected returns are maintained.

For example, annual payments for a 30-year mortgage are significantly lower than a 20-year mortgage. We may be able to afford (as a percentage of our budget) the former and not the latter. The mortgage company is essentially indifferent, the 20-year mortgage simply requires a higher level of reinvestment by the mortgage company to maintain a constant magnitude of investor return. The fact that book depreciation changes is not of economic concern. It may be of great practical concern in the sense that few of us could afford to pay our electric bills or mortgages if the total capital costs were recovered in one month. In reality, electric utility costs are usually not levelized. Costs are recovered in accordance with the curves depicted in Figure 2. The levelization or present valuing of costs is simply done to establish a common basis for economic comparisons.

The existing independence and distinct separation of objectives between electric utility rate making and investment analysis does not allay the demands of many utility analysts for absolute consistency in cost recovery procedures regardless of whether costs are annualized in rate hearings, present valued, or levelized. The absence of cost recovery consistency often causes them to question the correctness or internal consistency of determining equivalent costs using the tax adjusted discount rate. As previously noted, book depreciation changes from straight line because we have made revenues straight line.

Suppose a regulatory commission with the objective of more evenly distributing the recovery of nominal capital costs decides to levelize them for rate making purposes. What changes would be necessary in the proceeding to accommodate this change? Namely, the accounting convention of straight line book depreciation. The use of straight line book depreciation to determine the rate base on which investors are allowed to earn a return would no longer be valid. Book depreciation would simply equal the annual cash realization. This change would not concern investors since they would still be earning a return on unrecovered investment. It is interesting to note that tax laws and regulatory procedures currently require exotic adjustments to the rate base to accommodate the multitude of conventions for handling accelerated depreciation, tax credits, etc.

Attempts to reconcile the straight line capital cost recovery schedule with the changing cash available for capital recovery schedule resulting from the levelization of revenues has created scenarios involving the borrowing and repayment of capital cost recovery deficiencies and surpluses. The necessity of other projects to balance the straight line dogma is sometimes proposed. For these "problems" and "solutions" to arise, the rates developed in rate making must be ignored (while holding on to the straight line assumption for book depreciation) while prices for utility services are determined on a levelized basis. From a practical viewpoint, it is not necessary to consider other projects or develop borrowing and repayment mechanisms.

In summary, the tax adjusted discount rate is necessary to correctly determine equivalent utility costs. These costs are used primarily to facilitate economic comparisons. The levelization of utility costs using a discount rate to determine equivalent fair prices for alternative energy sources and to value energy conservation measures has increased the need for utility executives to understand the role of the discount in utility investment planning.

V. CONCLUSIONS

1. A thorough understanding of the discount rate is necessary for utility managers to effectively direct corporations.

2. The country needs rudders, compasses, and clear energy objectives.

3. The amount of alternative energy development and conservation investments made depends on the discount rate used to determine marginal costs.

4. The discount rate used by utilities affects the nation's dependence on foreign oil.

5. Payments to power producers by utilities for capacity and energy following accounting conventions would be consistent with actual marginal costs and would increase alternative energy development.

6. The separation between cost recovery methods developed for rate making and the procedures used to facilitate economic comparisons of investment alternatives needs to be recognized.

7. With the volume of information increasing in the age of microprocessors, more attention needs to be focused on what the numbers mean and the desirability of utility investment objectives.

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Figure 1

Public Utility
Decision Framework

ASSUMPTIONS

General Economic Conditions

- inflation rates

Specific Project

- capital costs

- operating costs

REGULATIONS AND ACCOUNTING

Annual Cost/Revenue Projections

ECONOMIC MODEL

Equivalent Cost to Utility

- levelized or present value

Economic Choice

- least cost to utility

HUMAN JUDGMENT

- subjective factors

PROJECT SELECTION

TABLE E5

Verification of Cash Flows to Investors

Alternative Investments		End of Year 2
Debt Investor:	$400\ (1.10)^{2} =$	484.00
Equity Investor:	$600\ (1.15)^{2} =$	793.50

Utility Investment--Returns from Table E4

Debt Investor:

End of Year 1

Principal return	$.4(473.94)$ =	189.58	
Debt return		40.00	
Total Cash Return		229.58	
Reinvests	$229.58(1.10)^{1}$ =		252.53

End of Year 2

Principal Return	$.4(526.07)$ =	210.43	
Debt Return		21.04	
Total Cash Return		231.47	
Reinvests	$231.47(1.10)^{0}$		231.47
			484.00

TABLE E5 (Continued)

Equity Investor:

			End of Year 2
End of Year 1			
Principal Return	.6(473.94) =	284.36	
Equity Return		90.00	
Total Cash Return		347.36	
Reinvests	$(347.36)(1.15)^{1}$ =		430.52
End of Year 2			
Principal Return	.6(526.07) =	315.64	
Equity Return		47.35	
Total Cash Return		362.99	
Reinvests	$(362.99)(1.15)^{0}$ =		362.99
			793.51*

*One cent error due to rounding

Conclusions: The tax adjusted discount rate properly models the present value and levelized cost of the investment to the utility.

Investment in the utility projects provides investors with cash flows which are equivalent to those obtained in alternative investments with equivalent risks.

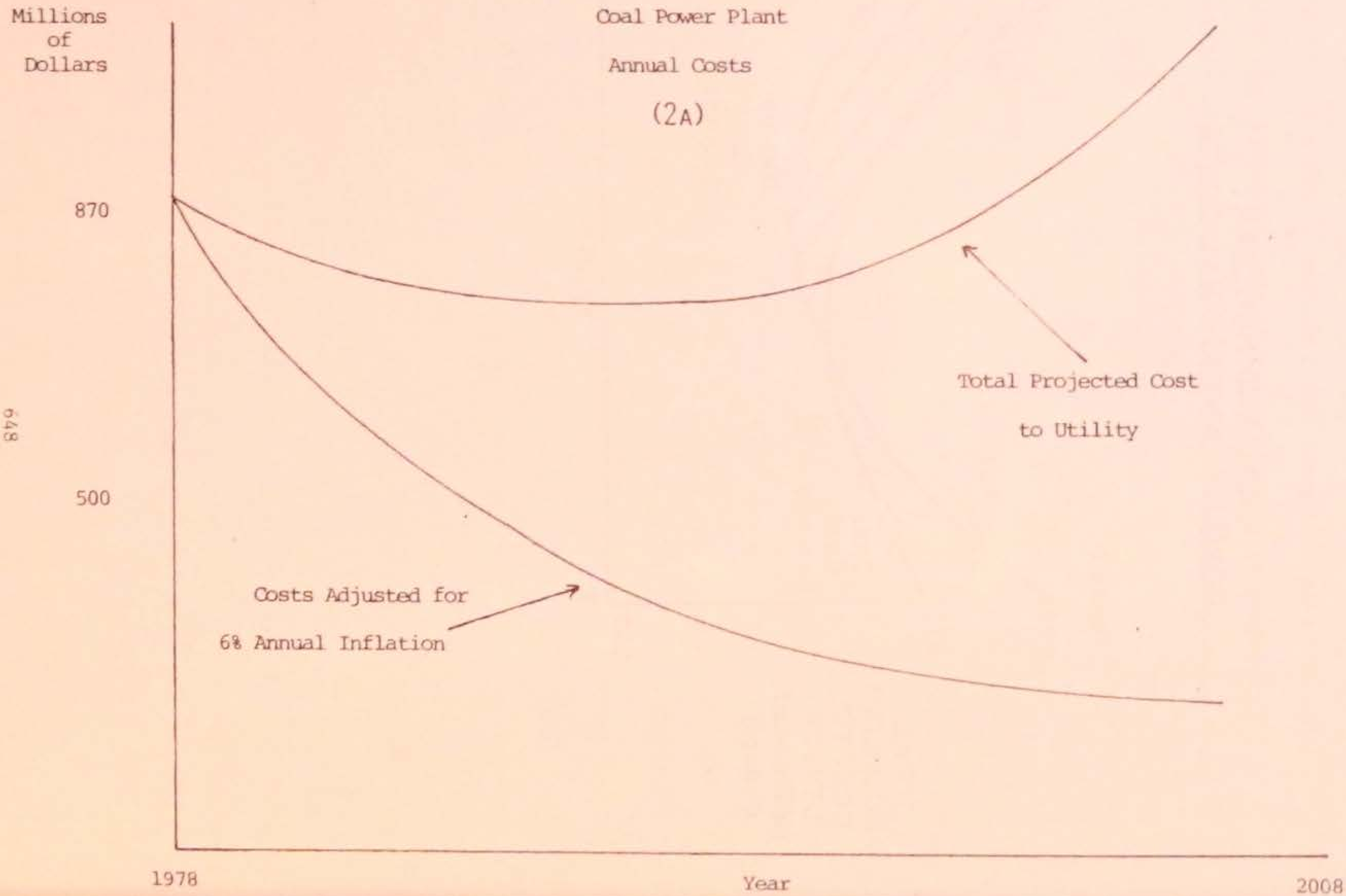
Millions of Dollars
Coal Power Plant
Annual Costs
(2A)
870
500
Total Projected Cost
to Utility
Costs Adjusted for
6% Annual Inflation
1978
Year
2008

TABLE E6

Nuclear Plant

Decommissioning Cost Recovery

Tax Adjusted Discount Rate

	Beginning Year 1	Year 1	Year 2	Year 3	Year 4
Present Value--11%	65.87				100
Levelized Value--11%		38.46	38.46		
Unrecovered Expenditure less Accumulated Cash Realization		0	-19.23	-40.57	-45.03
Cash Realization					
Revenue		38.46	38.46	0	0
Deduct					
Equity Return		0	- 1.73	- 3.65	- 4.05
Debt Return		0	- .77	- 1.62	- 1.80
Taxes (see below)		19.23	19.62	.81	-49.00
Total Deductions		19.23	17.12	- 4.46	-54.95
Cash Realization		19.23 +	21.34 +	4.46 +	54.95 = 99.98* = 100
Taxes					
Revenue		38.46	38.46	0	0
Deduct					
Debt Return		0	- .77	- 1.62	- 1.80
Disposal Expense		0	0	0	100.00
Total Deductions		0	- .77	- 1.42	98.20
Taxable Income		38.46	39.23	1.62	-98.20
Taxes		19.23	19.62	.81	-49.10

Conclusion--At the end of Year 4, the company has $100 for the disposal cost.

*Two-cent error due to rounding