Conference Series No. 15

NEW ENGLAND AND THE ENERGY CRISIS

ADELMAN
BRIMMER
BROWNE
CABOT
CAMPBELL
DEVANNEY
EISENMENGER
FICCAGLIA
HOWELL
HOUSTON
JUDD
LONDON
MACKENZIE
NICHOLS
RITCHIE
SALMON
STEINBERGH
SYRON
WEBER
ZIMMERMAN

PROCEEDINGS OF A CONFERENCE HELD IN

OCTOBER 1975

NEW ENGLAND and the ENERGY CRISIS

Proceedings of a Conference
Held at
Edgartown, Massachusetts
October, 1975

Sponsored by
THE FEDERAL RESERVE BANK OF BOSTON

THE FEDERAL RESERVE BANK OF BOSTON CONFERENCE SERIES

NO.	1	CONTROLLING MONETARY AGGREGATES	JUNE, 1969
NO.	2	THE INTERNATIONAL ADJUSTMENT MECHANISM	OCTOBER, 1969
NO.	3	FINANCING STATE and LOCAL GOVERNMENTS in the SEVENTIES	JUNE, 1970
NO.	4	HOUSING and MONETARY POLICY	OCTOBER, 1970
NO.	5	CONSUMER SPENDING and MONETARY POLICY: THE LINKAGES	JUNE, 1971
NO.	6	CANADIAN—UNITED STATE FINANCIAL RELATIONSHIPS	SEPTEMBER, 1971
NO.	7	FINANCING PUBLIC SCHOOLS	JANUARY, 1972
NO.	8	POLICIES for a MORE COMPETITIVE FINANCIAL SYSTEM	JUNE, 1972
NO.	9	CONTROLLING MONETARY AGGREGATES II: THE IMPLEMENTATION	SEPTEMBER, 1972
NO.	10	ISSUES IN FEDERAL DEBT MANAGEMENT	JUNE, 1973
NO.	11	CREDIT ALLOCATION TECHNIQUES and MONETARY POLICY	SEPTEMBER, 1973
NO.	12	INTERNATIONAL ASPECTS of STABILIZATION POLICIES	JUNE, 1974
NO.	13	THE ECONOMICS of a NATIONAL ELECTRONIC FUNDS TRANSFER SYSTEM	OCTOBER, 1974
NO.	14	NEW MORTGAGE DESIGNS for an INFLATIONARY ENVIRONMENT	JANUARY, 1975
NO.	15	NEW ENGLAND and the ENERGY CRISIS	OCTOBER, 1975

FOREWORD

For many years New England has suffered from high energy costs which have affected both the pattern and the pace of economic growth. The oil embargo of 1973 and the resultant tripling of oil prices intensified this long-standing problem and in addition awakened the region to the possibility of future energy shortages. In an attempt to contribute to the solution of these problems the Federal Reserve Bank of Boston sponsored this conference on New England and the Energy Crisis.

We hope that publication of these proceedings will aid the understanding of the alternatives available to meet New England's energy needs. A summary of the views presented and of the policy conclusions with which most conference participants would agree is included as the first paper in this volume.

Frank E. Morris

Frank E. Morris
Federal Reserve Bank of Boston

CONTENTS

New England and the Energy Crisis: Summary and Policy Conclusions

Lynn E. Browne*

Since the passing of the days when wood and water were primary energy sources, New England has suffered from high energy costs; and while the region's relative disadvantage diminished considerably in the post-war period, these gains were eliminated by the 1973 oil embargo. Not only did the embargo result in a tripling in the price of oil, but it also awakened the region to the possibility of energy shortages, both man-made and natural. Will there be sufficient energy in the future, at an acceptable price, to provide the standard of living New Englanders have come to expect?

The conference, New England and the Energy Crisis, was an attempt to clarify the choices posed New England by this critical question and, where possible, to develop policy recommendations. The following is a summary of the conference findings.

The New England Energy Problem

Lacking local sources of coal, natural gas and oil New England consumers have traditionally paid high prices for energy. In 1947 costs to manufacturers in New England were twice as high as costs to firms elsewhere. Over the next 25 years this differential narrowed considerably and the region became less dependent on energy through increased specialization in the service industries and high technology manufacturing. However, the price increases following the oil embargo in the fall of 1973 more than offset these gains. Between 1971 and 1974 energy costs in New England rose 145 percent, compared to 56 percent elsewhere. The reason for this differential increase can be found in the mix of fuels in New England. The region is heavily dependent on oil and uses relatively little gas, the fuels with respectively the greatest and smallest price increases over this period.

*Economist, Federal Reserve Bank of Boston, and Ph.D. candidate at the Massachusetts Institute of Technology in the field of utility economics. She was previously associated with the Department of Administration and Finance of the Commonwealth of Massachusetts.

The Role of Oil

Oil is by far the most important fuel in New England. In 1972 petroleum products accounted for 79 percent of the region's energy consumption for nontransportation purposes, compared to less than 30 percent nationally. Consequently, the supply and price of oil is central to the future economic growth of New England.

The outlook is not promising. Unless consumption patterns change substantially, world demand for oil may surpass production capabilities from conventional sources within this century. Moreover, even if shortages do not develop, New England will probably continue to pay high oil prices. Most of the region's oil is imported and while the price reflects the actions of the cartel, the Organization of Petroleum Exporting Countries, rather than the scarce nature of the resource, there have been no important signs that the cartel is weakening. Unlike cartels of history this involves sovereign nations — nations which could, if necessary, resort to force to keep their fellow members in line. At the same time the consuming nations have developed no effective counter-measures and, in addition, have allowed this lack to become well known. In the face of such a situation there is little a region or state can do to protect itself. The best course is for purchasers to remain alert to possible weaknesses in the cartel and to take advantage of price shaving wherever it occurs.

At first glance the prospect of an oil discovery off the Atlantic coast appears to offer the New England region security of supply and relief from high prices. In fact, however, the possibility of a significant change is exceedingly remote. The largest find credible would not completely eliminate imports for a single year. Prices would be determined by the marginal barrel of oil which would continue to come from the OPEC nations.

However, although prices would not fall, the discovery of oil on Georges Bank would still be beneficial to the region. The substitution of oil from Georges Bank for high-priced OPEC crude would produce additional revenues for the Federal Treasury and increased profits for the oil companies. These would be shared in by New England taxpayers and investors. There would also be favorable employment effects, although these would probably be no greater than those resulting from any moderately large firm moving into the area. However, for individual communities such increases could be very important. Offsetting these benefits is the possibility of environmental damage, particularly from the onshore developments likely to be associated with the discovery. This is a real danger but one that can almost certainly be controlled if the state and local governments are given adequate planning time and resources.

Alternative to Oil

To some degree New England has already begun to reduce its dependence on oil. Only 30 percent of the new electric power capacity planned for the next ten years is oil-fired. The rest is all nuclear. With the rise

in fuel prices oil plants are no longer economically competitive for base-load power generation.

However, although nuclear power is the lowest cost alternative, some view this choice with alarm. There is concern over operating accidents, leakage of stored wastes, and more recently sabotage and terrorism. To date, the safety record of nuclear has been good and most experts appear to believe that with vigilant management the possibility of a serious accident is extremely low. There is, however, considerable disagreement as to whether the industry and regulatory agencies are capable of such vigilance.

In addition, the utilities themselves are far from happy with an economic situation which makes nuclear such an obvious choice. In building a nuclear plant they are subject to far more regulation than they would be with coal or oil, and the longer lead times of nuclear construction place unprecedented demands on their planning capacity. Most importantly, the construction costs of a nuclear plant are much higher than those for fossil fuel, and in recent years utilities have had great difficulty attracting investment funds.

Unfortunately, fossil fuel is simply not a viable alternative for base-load power in New England. Oil prices are too high and the supply too uncertain. If nuclear construction costs continue to escalate, coal might become a feasible fuel for the region — but only if environmental standards were relaxed: the need to install costly desulfurization equipment ensures that the cost advantage remains with nuclear. Indeed, scrubbers effectively eliminate coal from consideration for even intermediate-load plants. Here oil remains the lowest cost alternative despite its obvious drawbacks.

In the face of this dilemma — continued dependence on the vagaries of the international oil market or what some have termed the "Faustian bargain" of increased reliance on nuclear power — what policies should New England demand as part of the national energy program?

Policy Recommendations

1) Encourage Development of New Energy Sources

The worldwide demand for energy generated by a satisfactory rate of income growth is likely to outstrip the maximum feasible production from conventional sources, particularly oil, within this century. Even with a major expansion in the contribution of nuclear and coal, new sources must be developed.

In the short run, or the next 25 years, these new sources are probably limited to oil production from tar shales and sands and the gasification or liquefaction of coal. Solar energy will play a role in water and space heating, but many doubt that it will make a significant contribution within this time period.

In the long run the possibilities are many. Solar energy will undoubtedly become important not only for heating and cooling, but possibly also for the generation of electricity and the conversion of organic matter into fuels. Power from nuclear fusion may become a reality and we may learn to make use of the heat stored in the earth and the oceans.

The conference did not explicitly consider what role governments should play in developing these new energy sources. However, it became clear in several sessions, particularly that on coal, that there is a great need to clarify the circumstances under which development is allowed to take place. For example, an important hope for the near term is the gasification of coal. However, the cost of coal can be significantly affected by restrictions placed on mining. Thus, there is a trade-off between the availability of low cost fuel and the possibility of health and environmental damage. Not all the choices involve environmental goals. In many respects the problems of developing new energy forms are analogous to those faced today by the electric utilities. The capital outlays that will be required are enormous. Will the profits necessary to attract these investment funds be tolerated? The public, through its governments, must decide, and decide within a very constrained time period, where its priorities lie. Today's atmosphere of uncertainty and the fear of restrictions being imposed after development has begun may well be more inhibiting than the restrictions themselves.

2) Encourage Conservation of Energy

Conservation can postpone for several decades the time when energy from conventional sources will be unable to meet world demand. This provides us with valuable time in which new sources can be developed. For the United States, and New England in particular, conservation also means reduced dependence on foreign energy sources, and therefore reduced exposure to the actions of cartels and monopolies.

Most conference participants appeared to believe that the price system has already demonstrated considerable effectiveness in accomplishing our conservation goals. The high prices following the OPEC embargo had already produced significant cutbacks in demand before the first effects of the recession were felt. Important opportunities for further reductions remain. Energy conversion efficiencies can be improved significantly, particularly in automobile transportation, electricity generation and industrial use.

The great drawback to reliance on the price system is, of course, the impact on real incomes, and many believe that high energy costs fall disproportionately on those least able to pay. In general, the conference felt that holding down prices is an inefficient, and in the long run perverse, way of achieving social goals and in particular maintaining income standards. However, it also recognized that adequate protection for the low income consumer may not now exist.

3) Deregulate Natural Gas Prices

Nowhere is the need for conservation greater than in the consumption of natural gas. Since the late sixties additions to reserves have failed to keep pace with increases in demand and these shortfalls are now resulting in production shortages which in parts of the country could approach crisis proportions.

The regulated price of gas offers insufficient incentive for exploration and development at the same time as it encourages consumption. In addition the regulated price fails to recognize that gas as a fuel has many uniquely desirable characteristics which would cause it to command a premium in some uses. With regulated prices the customers prizing gas most highly are unable to bid it away from those users who could much more easily substitute other fuels.

Deregulation would increase supply by encouraging exploration and by making the continued operation of the less profitable fields more attractive. At the same time the higher prices would ration demand and reallocate it to those uses where it is most valued. In addition, for New England, deregulation offers important beneficial side effects.

In the fall of 1975 the cost of natural gas per million Btus was less than a third that of residual oil. However, in New England oil accounts for close to 60 percent of industrial energy consumption and gas only 20 percent; nationally oil is slightly over 20 percent of total consumption and gas almost 50 percent. Thus any change which raises the price of gas will affect the rest of the country much more than New England and will tend to equalize energy costs.

This improvement in New England's competitive position is not without cost to the region's one million gas customers, most of whom are residential. Moreover, in the very short run there will be no quid pro quo in the form of greater security of supply. The firms supplying New England have already made adequate provision for this winter; and in any event current Federal allocation priorities ensure that our residential customers will be the last cut back. However, even a substantial increase in the field price of gas is likely to have a relatively modest impact on final costs since the wellhead price now accounts for only 10-15 percent of the price actually paid by New England end-users.

Some feel that New Englanders should be cautious in advocating deregulation because of the possibility of a gas discovery on the Georges Bank. Gas from such a find could be landed in New England at a cost, in today's dollars, significantly below the present wholesale price in the region. Consequently, if New England received a large share of the find, under regulated prices the cost of gas in the region would fall. If prices were not regulated, gas from Georges Bank would still be less costly than that from any other source; but the unregulated price of Georges Bank gas would probably be more than today's regulated wholesale price.

While the benefits from continued regulation could be substantial if gas is discovered, they are subject to a high discount rate. There is great uncertainty surrounding the potential size, and even the existence, of gas reserves on Georges Bank; and if gas is found, it will not be commercially available for eight to ten years. Moreover, it is not clear how much gas will actually come to New England. With no controls proximity would give New Englanders a great advantage in bidding for the gas. However, with regulation the allocation will probably be determined by the Federal Power Commission, and while efficiency will certainly play a role in the Commission's thinking, it will not be the only factor.

Lastly, some feel that deregulation is a moot issue. The high prices now prevailing in the unregulated intrastate market amount to defacto deregulation, as increasingly reserves are dedicated to these uses. However this offers small comfort to New England, for it means that industries willing to pay a premium for the special features of natural gas will gravitate to those areas where gas remains available.

4) Higher Rates of Return for Electric Utilities

Like the natural gas shortages, the problems of the electric utilities demand a choice between the present, obvious needs of the consumer and the region's longer-run self-interest. Utilities have staggering capital requirements. Because of recent additions to capacity New England firms have somewhat more flexibility in scheduling new units than their counterparts elsewhere. However, their investment needs remain very great. Costly borrowings to finance the expansion programs of the late sixties and seventies, together with stable or declining earnings, have severely eroded coverage ratios, limiting issues of new debt and preferred stock. At the same time the rates of return on common equity have fallen relative to the yields on competing investments with the result that stock prices have dropped below book values. In such a situation further stock issues dilute the value of the shareholder's investment.

Restricted in raising capital, the utilities have cut back construction programs substantially. Some of these cutbacks are called for because consumption appears to have levelled off; but further cancellations and deferrals could jeopardize the future supply of electricity or force the utilities to make very high cost stopgap additions to capacity. The answer is higher returns to equity. This, of course means higher rates today for the consumer although greater security of supply and lower costs tomorrow.

Regulators are understandably reluctant to accede to the necessary rate increases not merely because of pressure from the public but because they believe, often with good cause, that the utilities are not sufficiently aggressive in cutting costs or imaginative in reducing capacity needs through rate schedules. Thus a corollary of higher rates is well-funded, professional regulatory bodies. These would vigorously scrutinize costs, question demand projections and set efficiency goals. However, the utilities efforts at compliance would be rewarded with competitive rates of return. In this manner the public's immediate and long-run interest may be reconciled.

The conflict between short- and long-run goals is the heart of the energy problem. Each of the policies advocated by the conference implies an immediate sacrifice for the region's, and the Nation's ultimate prosperity. This will be painful and, some will feel, unfair; but unless action is taken the future could be sad indeed.

The International Oil Outlook: A Scenario Approach

Joch D. Ritchie*

It is not possible to discuss "The International Oil Outlook" without considering oil for what it is — just one source among several of the world's energy supply (and one that could in fact — and probably one day will — be dispensed with all together, given time, resolve and a great deal of capital).

But oil — notably Middle East oil — where real production costs for very large volumes of oil are between a dime and a quarter per barrel — is still the cheapest energy available to us. Thus, economically it is only sensible that oil plays a large role in our energy supply for decades to come; and, anyway the lead times for alternatives are such that, practically, we have no choice.

Why should we be so concerned with energy? Production depends on energy. And a better life depends on production — not only for those of us who are fortunate enough to enjoy the thin layer of cream at the top, but for the hundreds of millions of people who cannot yet count on having enough to eat. Production efficiency is not an end in itself; it is the means to an end which is clearly espoused by the very great majority of humankind. And, let me anticipate some potential criticism; this is not a materialistic philosophy. Rather, as Walt Rostow said at the end of his book *Stages of Economic Growth*, "The end of all this is not compound interest for ever and ever, but the adventure of seeing what man can and will do when the burden of scarcity is in large part lifted from his shoulders."

Before I get right into my subject, let me introduce another quotation. There is an Arab saying that "those who foretell the future lie even if they tell the truth." The only way to approach the subject, therefore, is by means of alternative scenarios, each a description of what the future world might be like, consistent within itself, and which can be used as a means of deciding what we want to do in the meanwhile. I do not mean to predict that any particular future will come about. Each one of the four that I shall discuss is possible. Each of us must make up his own mind as to which one he thinks is most likely. I will indicate my guess.

*President of Asiatic Petroleum Corporation, an American affiliate of Royal Dutch/Shell. An Englishman, he previously held a wide variety of positions for Royal Dutch/Shell all over the world. Before beginning his business career, he served in the Royal Navy for 14 years.

However, whichever of the future scenarios turns out to be the best approximation to reality, there is some very rough water between today and the time when we can begin to see which of the future scenarios is developing. Perhaps it helps to think of this "rough water" as a series of cataracts of which the first was the OPEC quintupling of crude oil prices. Each of these cataracts is a major discontinuity, and each will be an irreversible change. It is no good trying to swim against the current because you can't. If, however, you are alert to the rocks and steer your craft successfully, you can get carried along to some hopefully calmer water pretty quickly.

Perhaps "calmer water" is not the right phrase for the first scenario. This is the possibility that the suddenness and magnitude of the increase in the costs of energy may lead to widespread economic chaos, to which governments react by deflating demand. This in turn leads to hyperinflation, and to the collapse of the system. In this country, at any rate, there are now hopeful signs that this is altogether too pessimistic an outlook. So let us dismiss it as a nightmare!

The other extreme, the idea that somehow or other OPEC could be cajoled, or forced, or maneuvered into having to reduce the price of oil to $5 or $7 per barrel, has had many influential adherents around the world. Would you agree with me now that we are right in dismissing this scenario as a "dream world," just as we have dismissed the preceding as a nightmare? There is a small possibility that either may come about; but let's concentrate on the other two scenarios which I suggest have a higher probability of happening. These we have called the "World of Internal Contradictions" (WIC) and the "New Belle Epoque." Figures 1 and 2 set out the main characteristics of each of these scenarios. My personal view is that the Belle Epoque is the more likely of the two. I am an optimist.

Let us now go straight to the issue of energy demand and supply. The year 1973 was in a sense the last year of an old era. Oil then supplied 50 percent and oil and natural gas together 75 percent of the energy demand of the World Outside the Communist Areas (WOCA). (Figure 3.)

One of the characteristics of the Belle Epoque scenario is that it foresees a 6 percent annual average growth in the world's economy. Compare this (Figure 4) with the record of the last decade and a half and you will realize that I am postulating the possibility of a substantially higher rate of growth than we have had. Now if we had continued the 1973 pattern of use and 1973 patterns of waste (using this word both in its technological sense and in the sense that implies a value judgment) you will see in Figure 5, in terms of million barrels a day of oil equivalent, how energy demand would grow along with increases in gross world product in the period through 1990. The question we must therefore ask ourselves is "What action do we have to take to meet this potential demand? What are the resources which could be developed by the year 1990?"

Since oil is my subject, let me start with what we call "conventional" oil, i.e., natural petroleum produced or producible using the technologies which are now within our grasp, and making certain assumptions about

Figure 1

SALIENT POINTS OF TWO SCENARIOS
FOR THE WORLD OUTSIDE
THE COMMUNIST AREAS (WOCA)

	Belle Epoque	World of Internal Contradictions
Long-term Economic Growth	WOCA average above the historical trend	Industrialized countries well below trend
Real GNP	1985 WOCA aggregate twice that of 1973	1985 WOCA level 50/60% higher than 1973
Energy Demand	1980 WOCA level 6% less than pre-crisis expectations	1980 WOCA demand 15% below pre-crisis expectations
Nonoil Supply	Development of international trade in coal and natural gas	Greater emphasis on indigenous resources
Oil Requirements	1980 WOCA demand 13% below reference line; moderate growth in W. Europe/Japan	1980 WOCA level some 25% below reference line; W. Europe/Japan demand at 1973 level
Oil Imports	Moderate growth in W. Europe/Japan to 1980	Absolute decline in 1980 W. Europe/Japan

Source: The alternative scenarios and the energy demand and supply situations implicit in each were developed by the planning staff of a Shell Service Company. They are based on published material from the OECD, the United Nations and the World Bank, as well as Shell's internal sources.

Figure 2

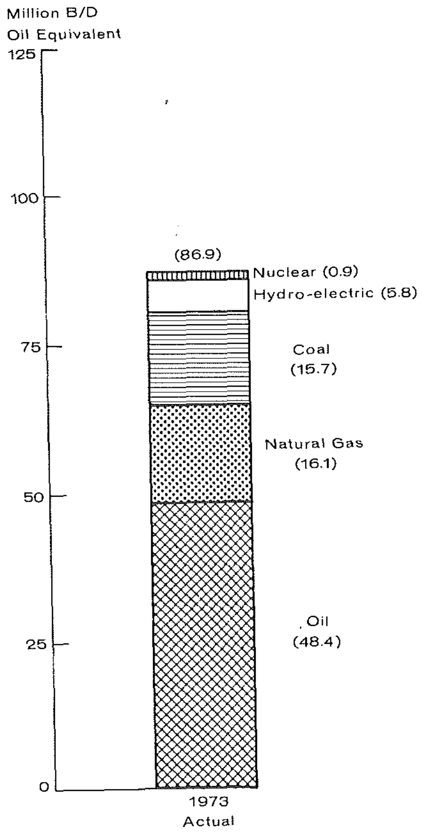
BASIC SCENARIO DATA

	I Belle Epoque 1973-80	II World of Internal Contradictions 1973-80
GNP Growth (%AAI)		
North America	4	3
Western Europe	4	2.5
Japan	7.5	5
Rest of World Outside the Communist Areas and North America (WOCANA)	8	4.5
WOCA	5	3
Energy Demand Growth (% AAI)		
North America	3.5	2.5
Western Europe	3.5	2.5
Japan	6.5	4.5
Rest of WOCANA	7.5	4.5
WOCA	4.5	3

Source: Shell Service Company.

Figure 3

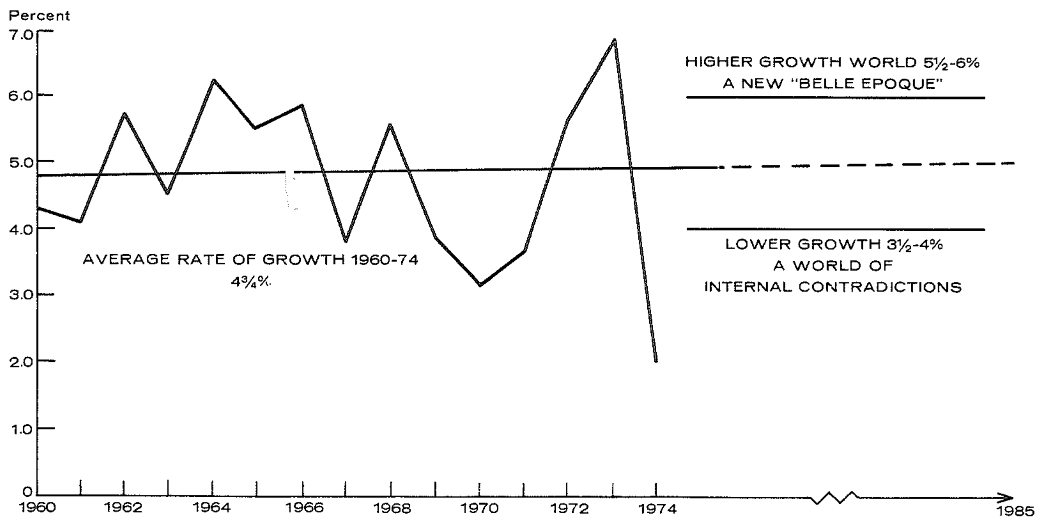
ENERGY DEMAND - WOCA



Source: Shell Service Company

Figure 4

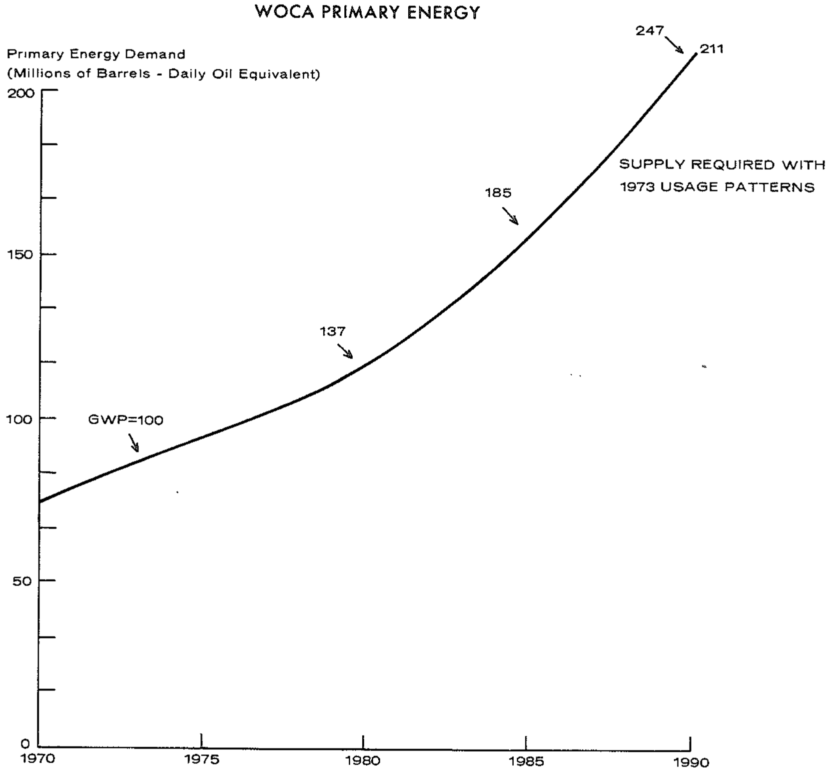
REAL ECONOMIC GROWTH RATES IN TOTAL OECD AREA
1960-1974-1985



Source: Shell Service Company

Figure 5

WOCA PRIMARY ENERGY



Source: Shell Service Company

the costs of alternatives and thus the price that will be paid for oil at the technological margin. The first characteristic of oil is that it is finite; it is a wasting asset and will not last forever. However, the presence of Professor Adelman as my critic today inhibits me from developing this argument from estimated figures of how finite it may be. Anyway I do not believe I need to, because it may be irrelevant. What matters is how much oil is found and how much the political owners of the oil expect to be found and at what level, therefore, they are content to see their reserves produced.

Figure 6 looks at a different area of the world — at "WOCANA" — the World Outside the Communist Areas and North America. (This includes those parts of the world where oil imports are vital to energy supply, and also those countries where oil production is the mainstay of the national budget and where the question of the relative value of oil in the ground as against money in the bank is a real one). It shows the recent history of additions to reserves, and a guess as to the future.

It is misleading to talk of OPEC countries as if they were homogeneous, and to overlook the fact that (for example) Algeria, Iran, and Indonesia can use every dollar their oil production can conceivably bring them, while others — Saudi Arabia, Abu Dhabi, and Kuwait — have enormous proved and potential reserves, along with small populations. These countries, therefore, do have problems of absorptive capacity, and real doubts about their ability to invest sensibly their growing surpluses of funds. It is realistic to accept that Saudi Arabia at any rate may believe — in the light of political and economic uncertainties — that oil in their ground may well be better than money in someone else's bank. There are indications of this from, perhaps, the eagerness with which Saudi Arabia is pressing the development of new oil provinces in the "Empty Quarter" of the country, when they already have in place productive capacity well in excess of their ostensible production plans.

Once we accept this, we must accept that there will be political as well as technical feasibility constraints on the oil that is made available. It is, I suggest, not unreasonable to deduce from the chart of probable future additions to reserves that some governments will constrain their production. So Figure 7 shows a possible conservation limitation to production and what the effect that even that limited growth of production may be expected to have on the ratio of reserves to production.

Figure 8 is a little complex; to start with, it shows what informed opinion in the oil industry regards as the maximum technically feasible availability of oil production, consistent with the upper and lower limits of the probable annual rate of additions to reserves. Against these are shown three lines of possible demand for crude and natural gas liquids. The top one is the expectation that we were looking at before the 1973 crisis; the next shows the spontaneous evolution of demand under the Belle Epoque scenario, (BE), while the third shows the same for the World of Internal Contradictions (WIC). But I have just argued that producing governments are likely to impose a conservation limitation. (Figure

9). This is marked Optimistic but Possible — it assumes that Saudi Arabia will be willing in the long term to have its oil reserves produced at the rate of ten million barrels per day. The gray area, which is now overlaid, shows the effect of spreading out over the future production potential not used in the earlier years. And this brings us face to face with our problem. If the Belle Epoque comes about, the maximum probable availability of oil — the top edge of the gray area — and the spontaneous evolution of demand part company soon after 1980. And the problem is a larger one still if we look at the conservation limitation.

Increases in energy costs have, however, persuaded consumers to use less. (It is encouraging to be reminded that the law of supply and demand does indeed work!) And there is still considerable potential for further energy savings not all of which, of course, can be achieved in the short run. However, at a maximum, we can only count on this for a 20 percent saving in this century.

So now I come back to the previous chart to show the effect of savings on the spontaneous evolution demand line. From this you will see that by 1985 — by only ten years from now — we must have some nonconventional sources of oil — shales and tar sands for example, beginning to make their contribution.

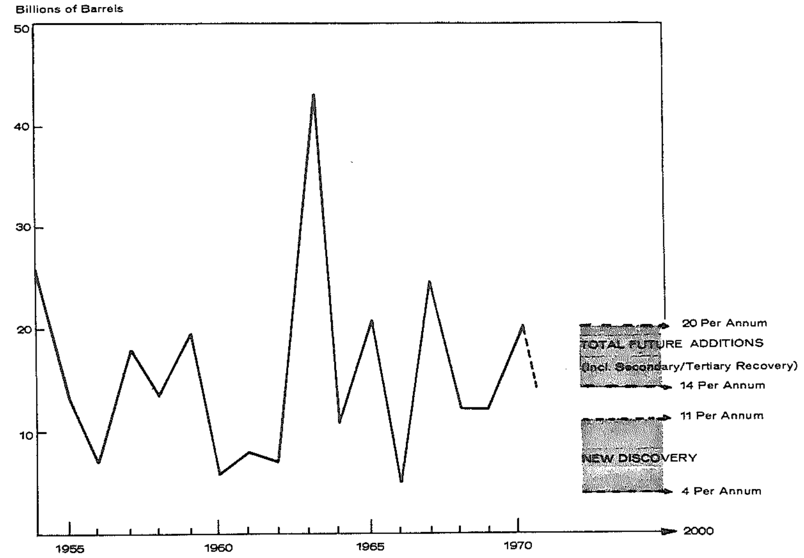
I have talked about oil and I have said that alternatives will have to play their part. Figure 10 shows, for the period to 1990 and under the Belle Epoque scenario, where it is reasonable to expect WOCA primary energy to come from. Note these three features:

- That while oil's contribution grows, internationally traded crude and products will remain at the end of this century at substantially the same level as in 1973. Indigenous oil and oil from tar sands and shale will account for most of the growth in the oil sector;
- Substantial growth has to come from nuclear and coal. A decade from now we may expect coal to make substantial contributions in environmentally more acceptable forms, i.e., by gasification or liquefication.
- You all know the amount of enthusiasm that the idea of solar and geothermal energy generates. The contribution that I believe they can make in our life-times is so small as to be barely visible on the chart. Nevertheless, solar energy is inexhaustible; and at any rate it is right that we dedicate a lot of effort and investment to it.

Let me leave you with one final worry: and again time does not permit me to go through the arguments which I believe limit the potential for coal and nuclear and natural gas. They consist of environmental, engineering, and financial problems. Taking these constraints into account, this (Figure 11) is a list of the maximum amounts of energy which are

Figure 6

ANNUAL ADDITIONS TO RESERVES—WOCANA

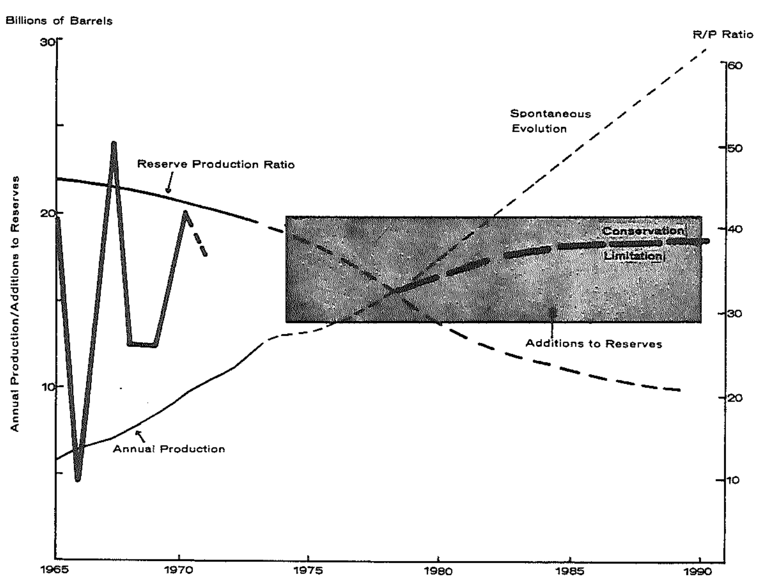


Source: Shell Service Co.

Figure 7

RELATIONSHIP BETWEEN ANNUAL CRUDE/NGL PRODUCTION AND ADDITIONS TO RESERVES

WOCANA

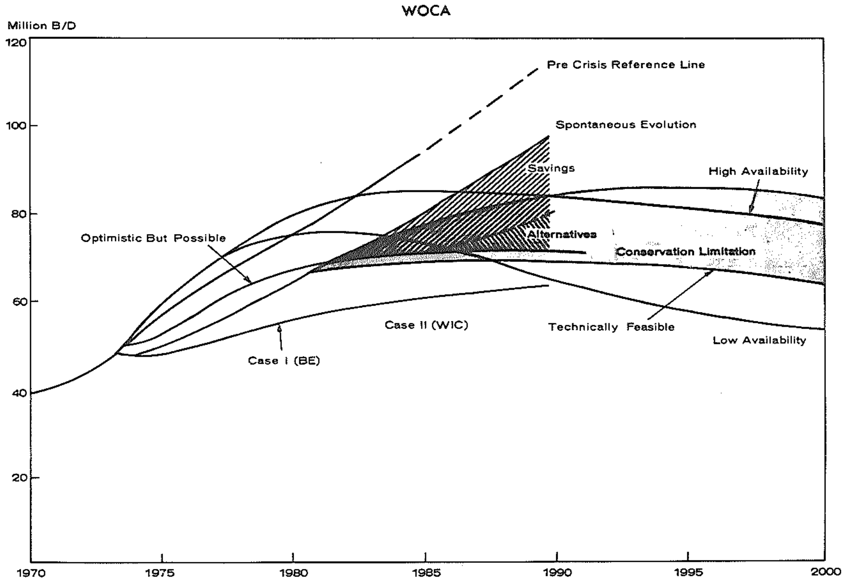


Source: Shell Service Company

Figure 8

LONG TERM CONVENTIONAL CRUDE/NGL SUPPLY AND DEMAND

WOCA



Source: Shell Service Co.

Natural Gas Liquids

Figure 9

ENERGY CONVERSION EFFICIENCIES
(Percent)

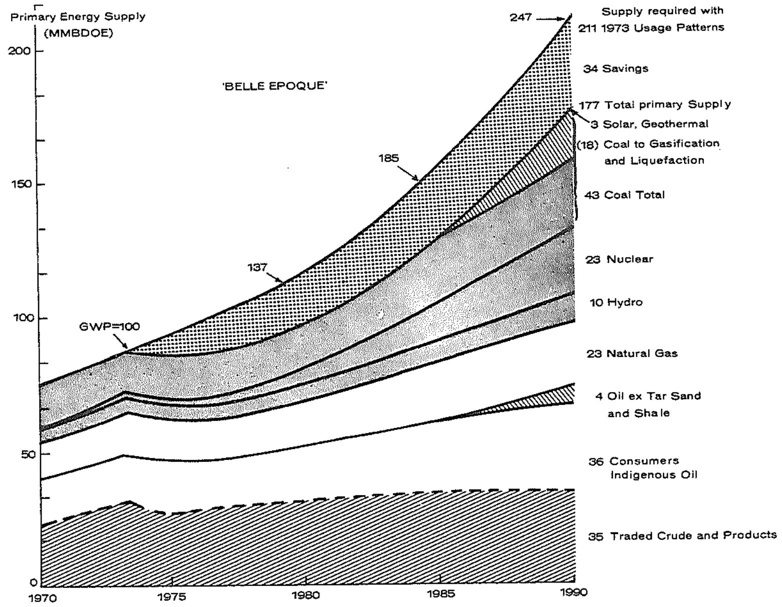
	Actual 1970	Possible 1985	Practical 1985	
Electricity Generation (UK)				
Overall	28	40	35	Write-off obsolete plant.
Industry				
Overall	69	75	72	New plant & improved servicing
Transport				
Road — Gasoline	14-18	22	20	Lean mixture & injector systems.
Diesel	30-35	35	35	Limited scope for improvement.
Battery Electric	60(18)	75(27)	75(27)	Improved lead/acid batteries & more efficient generation.
Rail — Diesel	30-35	35	35	Little scope for improvement.
Electric	85(27)	85(30)	85(30)	Generation improvement.
Sea — Diesel	35-40	40	40	Now available for largest vessels.
Turbine	30	30	30	Little scope for improvement.
Air — Gas Turbines	25	27	25	Improvements matched by noise. Abatement losss.
Overall	20	30	23-27	Determined by proportions of gasoline, diesel and electric vehicles.
Domestic Overall	61	70-75	68-72	Improved burners and servicing.

() = Denotes efficiency of complete electricity cycle.

Source: Shell Service Company

Figure 10

WOCA PRIMARY ENERGY



Source: Shell Service Co.

Figure 11

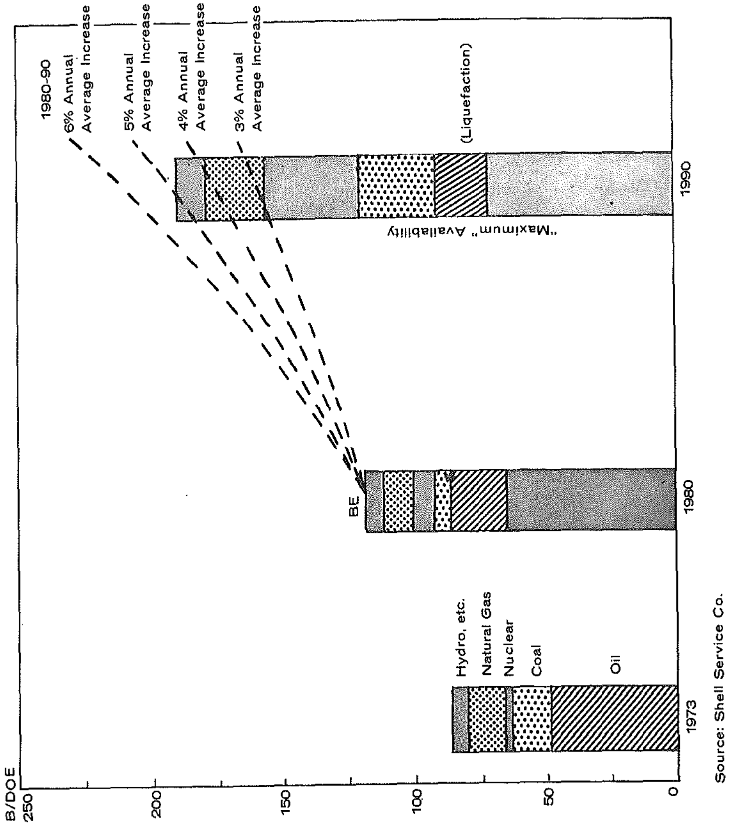
MAXIMUM AVAILABILITY OF ENERGY
WOCA: 1990

		Million b/d Oil Equivalent Maximum	(1973 Consumption)
Oil — Conventional — Tar Sands — Shale	71 million b/d 2 million b/d 2 million b/d	75	(48)
Natural Gas	1150-1450 x 10^9 m^3	20-25	(16)
Coal — Hard Coal — Brown Coal	2800-3400 x 10^6 tons 400-600 x 10^6 tons	35-45	(16)
Hydro, Geothermal, Solar, etc.	450-550,000 megawatts	10-12	(6)
Nuclear	1,000-1,400,000 megawatts	25-35	(1)
	Maximum Total	170-180	(87)

Source: Shell Service Company

Figure 12

AN AVAILABILITY CONSTRAINT
ON WOCA ENERGY CONSUMPTION UNDER THE BELLE EPOQUE



Source: Shell Service Co.

likely to be available in 1990. And Figure 12 shows that this maximum will barely support a 5 percent annual average increase between now and 1990.

It does not do, if you are as I am an optimist by nature, to end with a worry. There is enough deuterium in the oceans to support, through the nuclear fusion process, the level of energy consumption at which we shall have arrived by the end of this century for one-and-a-half million years. This planet receives enough energy from that big fusion reactor out there, 90 million miles away, to supply us forever with 10,000 times that energy consumption. If we put our minds and our money to it, we can learn how to capture sunlight and we can learn how to duplicate on a small scale the sun itself here on earth.

Let me end with one final quotation. It is one half of my recommendation to every government in this world as to its energy policy; it is a Spanish saying: "Do what you want," says God, "and pay the price." The other half is "But do something!"

Discussion

M. A. Adelman*

We're much indebted to Jock Ritchie for that look ahead and he ended it on just the right note with a Spanish proverb, "For God's sake do something." My sympathies, however, run north of the border, with a Frenchman who said, "For God's sake, not too much zeal." Or with my eminent colleague Charles P. Kindleberger who said, "Don't just do something, stand there a minute and think." Those are statements of philosophy and preference only. What I am going to do is supplement what Jock Ritchie has said. He has given us a very illuminating look ahead but he didn't say anything about prices. And yet prices are what every other paper submitted to this conference has been concerned with. And that is what I'm going to add.

Now I'm going to deal with really just one aspect of prices and that is the role played by scarcity. Conventional oil and gas are scarce; they are limited. Everybody has always known this. The trick is to know where those limits are. And the latest paper estimating those limits, to which I will refer later, starts out very wisely by citing the old estimates. At one time it was estimated that there were about 10 billion barrels of oil in the earth, which is less than we now use every year. But I'm going to talk about a world that isn't — namely a world which is ruled simply by scarcty — in order to illustrate what I think is the world that is, namely one that is ruled by a monopoly. Conventional oil is really important for just one reason. It is cheaper than coal and what you can get out of shale and nuclear power and other energy sources. Anybody who has a stock of conventional oil has a valuable asset, valuable to the extent and only to the extent that it is cheaper than anything else.

Let us suppose that in 25 years, and I have a reason for choosing that figure, we are no longer relying on the further development of conventional oil and that hereafter the price will be set by what it costs to get equivalent energy out of coal and shale. A current oil company estimate of the cost of these alternatives is $16 a barrel in real terms. And I would just as soon use this, not because I think it is likely but because it's a good starting point. It may, of course, be a good estimate. It may turn out to be a good one if we let Mr. Rockefeller persuade us to spend $100 billion in order to freeze ourselves into a technology that is already obsolete. If that happens, then we will probably surpass that $16.

*Professor of Economics at the Massachusetts Institute of Technology. He has been associated with that faculty since 1948 and has done continuing research on world energy problems. His publications include *The Supply and Price of Natural Gas* (1962), *Alaskan Oil* (1970) and *The World Petroleum Market* (1972).

Let us suppose that by the year 2000 there is still plenty of conventional oil around but the price is set by what it takes to bring the unconventional sources on stream, and therefore is $16 a barrel. Now anybody who in 1975 has a stock of oil and looks forward to that happy occasion of increased scarcity will not part with the oil unless he can get an amount which represents the difference between price and extraction costs in the year 2000.

So if the extraction costs 25 years from now are ten times what they are today, the value or surplus of that asset in the year 2000 will be $13.50 a barrel. And if you discount at what I think is a modest rate of 10 percent real, you find that $13.50 is worth $1.25 today. Adding to this a current extraction cost of 25¢ you get a price of $1.50, slightly higher than the price a few years ago.

Only recently, with a price of $1.25 for Persian Gulf oil, the oil trade — according to internal documents of which a few have drifted into our tent — was only concerned about increasing glut and declining prices. Such concerns were justified, for the price in 1975 implied by a scarcity-determined price of $16.00 in the year 2000 would be no more than $1.50. Clearly, scarcity has little to do with today's prices, which are almost an order of magnitude above this.

Now let me explain why I chose a 25-year time horizon. For the ten years before 1972, the last year of relative quietude, the worldwide — or what Jock Ritchie calls WOCA — rate of growth in oil consumption was 7 percent. I call this the autonomous shift, meaning that with no price changes growth in population and income led to the 7 percent figure. However, much of this growth was at the expense of other energy sources, chiefly coal; so that over time you would expect the growth in oil to converge to the growth in total energy consumption, or approximately 4 percent. Now that is a slight overestimate because the real price of energy declined during the sixties but we will have to put up with that slight bias.

Thus, for the period 1975 to 2000 one could reasonably assume that consumption of oil would grow at an average rate of 6 percent if there were no price changes. If, however, prices increase at the assumed rate of 10 percent per year, one must consider the response to these higher prices. With an elasticity of -0.5, which means that for every 1 percent increase in price, demand will decrease by 1/2 of 1 percent, the combined effects of the autonomous growth and the price response is a rate of growth of only 1 percent per year.

If consumption increases by 1 percent per year, then cumulative WOCA consumption over this 25-year period is 484 billion barrels. And if you think that the real responsiveness is a bit lower, perhaps only -.3, the cumulative consumption will be 625 billion barrels.

The question is, Against what stock is that to be measured? How much are we drawing down the inventory? Now I'm taking the latest, and I think the relatively conservative inventory forecast of John Moody of Mobil in a paper given in Tokyo last spring. Proved reserves in known fields, which are essentially money in the bank and which can be produced with existing technology and mostly with existing installations, wells, and gathering systems, amounted to 609 billion barrels at the end of 1974. So either we have quite a comfortable surplus or a very small deficit. Now in considering how easy or difficult it is to make up that deficit, I shall turn to John Moody's paper. He says that ultimate reserves in the WOCA area amount to 1,250 billion barrels and if you take account of improvements in technology to permit deeper offshore recovery you may double this. So it is pretty clear that if we simply look at the limits of our conventional oil reserves and ask ourselves what effect they have on price, we have to say none. I'm reminded, I must say, of that Mae West movie where somebody admires the rock on Mae West's finger and says, "Goodness, what a diamond." And she says, "Goodness had nothing to do with that." Scarcity and finite resources and all of that sort of thing have nothing to do with the price of oil which is set now and has been set in recent years by a monopoly, or a cartel to be more exact.

The reason for distinguishing between a high price set by scarcity and a high price set by a cartel is that these are two different ball games and if you are trying to survive, it calls for an altogether different kind of reaction depending on what has generated the high price. First and foremost, there is a whopping big surplus of producing capacity today — far and away the biggest that has ever been seen and one which is going to persist. Some say it will last for at least five years, others for ten or more years — I don't know. The question, however, is how successful the cartel will be in containing this rather formidable pressure. How strong will it be and for how long?

There are two things you have to say about the cartel. One, it is very strong and two, it is very fragile. Cartels are like that. Now you can see this clearly enough in the example which I want to pick from what Jock Ritchie said of Saudi Arabia, where, as he would put it, they prefer to keep their oil in the ground rather than put the money in the bank. Now I submit that if we credit them with ordinary common sense this explanation will not wash. Because if you look only at proved reserves, at present rates of production they now have about 50 years supply and the trade-off for them is between producing it today and producing it 25 or 50 years hence. The present value of that barrel far off is nothing, so that they are better off taking the barrel out and putting it in the bank, even if they think it is a very shaky bank. At least they have the use of the money for a few years before everything goes to hell.

If you credit them with common sense you have to say whatever it is that is making them keep the oil in the ground, that is not it. No, actually what makes them keep the oil in the ground is not political considerations. It is good, common, monopolistic sense. If they produce more than a certain amount they will break the price structure. And they are not about to do that. It makes perfectly good sense on their part to keep that oil in the ground forever and ever in order to avoid driving down the price today. Yet, I will confront you with what seems like a contradiction, a fact of which we have somehow to take account. They are actively exploring for new oil and apparently with very good success. Now the only way to account for this conduct is as a hedge against the collapse of the cartel. Collapse is a word used too much, but say the eventual collapse, and in the meantime the severe erosion of the cartel. If that happens, then restraint is off and there is no reason for them to hold production down to current levels or even two or three times that much. And they want to have the resources on hand with which to expand. This is really a pretty cheap way in which to hedge against the cartel's demise. The exploration does not cost them all that much and the possible rewards for it are very great. So they are paying insurance against something that, of course, they hope with all their hearts is not going to happen. And that is all we need to say about them. But the profitable moral for us is that people at the very center of the monopoly are perfectly well aware of (1) its strength and (2) its fragility.

Now its fragility doesn't need any emphasis from me. It is basically that current production surplus that overhangs them and the possibility that it will do to this cartel what it has done to almost every cartel since the world began — to break the arrangement by causing one to cheat against the other. The mutual distrust or fear of being done out of a market will lead people, as it always has, to make incremental sales at somewhat lower prices lest others take the market away from them. And in a very small way, and I think not a significant way, this is what has been going on during the past year with the weaker sellers, who coincidentally are the ones with premium high quality oil, giving away those premia because they are trying to prevent a severe attrition of their sales. So this is the fragility. But the sources of strength are also considerable and I won't try to draw up any balance sheet (because I don't know how at the moment) of which is going to overbear the other or how soon. The strength, however, is great and it lies in the following. First, this is a cartel of sovereign nations. They are not subject to any law of man or God. And this sets them apart from an ordinary cartel of companies, which are still subject to the coercive power of a state. Because as our peerless leader reminds us, power grows out of a barrel of a gun. These monopolists have the guns on the spot and what is more they have the guns to intimidate each other. As I think Jock was remarking last night at dinner, the Saudis will pay due respect to the guns and the jet aircraft on the Iranian side, just as the Saudis' little neighbors will pay due account to the Saudis' tanks, half-tracks and helicopters which we are furnishing them in large amounts. So this is one source of strength that the current cartel has and it is pretty important.

The next source of strength is that they don't face the very difficult divisive and insoluble task of prorating production. They don't have to share the market. They have the companies to do it for them and the companies, I hasten to say, do this without daring to practice anything anybody could call collusion. Each company sells what it can and produces what it can. So the amount supplied is only equal to the amount demanded, and there is no pressure on prices. This is a funny sort of market-sharing mechanism. It is haphazard. It is just as if all of us here were the cartel and we couldn't agree on a market-sharing scheme. So we call in somebody from the outside and say, "All right, you're the one who is going to tell us how much we can increase or have to decrease last year's sales." Now he does this without knowing whom to help or to hurt. But so long as we abide by his decision, we're in good shape, and the governments are doing just this. So despite all the nationalization and waving of flags, and the decrying of blood-sucking western imperialists, they are not throwing out the oil companies because they can't do without them.

And, of course, the last source of strength is that unlike all other cartels they don't have to worry about their customers and their antagonists' dirty tricks. Because customers, since the world began, have always looked around for ways of inducing cartelists to cheat one against the other. But here we are concerned with governments. And the last thing the governments in the consuming areas want to do is be so rude as to try to disrupt the cartel. The policy of the United States (I disagree with Jock, we do have a policy) was summed up perfectly about a year ago. President Ford was making a tough speech in Detroit, "Nations have gone to war for less than this" and Mr. Kissinger was making a tough speech in New York, when John Sawhill, then the Federal Energy Administrator, was asked, "What plans does the government have to get world oil prices down?" And Mr. Sawhill said, "No plans, there aren't any." Mr. Sawhill apparently has been reading Mark Twain who advises: "Always tell the truth." This will please some people and astonish the rest. Mr. Kissinger was furious; Mr. Sawhill was fired. That essentially is the policy. The empty barrel makes the most noise. And that's us.

Well in this kind of a world where prices have been raised, and will be raised further when industrial activity picks up, to roughly ten times where they would be if they reflected real scarcities; where it's controlled by a group of governments who have had no trouble sticking together and probably will not have a great deal in the future; where there is a huge overhanging glut which will be with us, what kind of a policy makes sense? I would say I didn't come here to talk policy but I will allow myself a word or two about it. And I would say that the best policy is not too much zeal, but hang loose and watch for things to happen, because as an individual, as a state (I didn't say a nation), as a company, or as a region, there is nothing you can do about it except to see what cracks in the wall you can discern which will leave you a little better off.

Interchange

Jock D. Ritchie and M. A. Adelman

Mr. Ritchie:

I would just like to make two very brief criticisms which are the kind one should not have to make, I think, to a professor of economics, certainly not at MIT. Morry, I think you've got your two discount rates wrong. I think you've confused current and today's dollars. In real money terms the discount rate is very rarely much above 3 percent; it's usually nearer to 2 percent and in inflationary times one finds oneself in the awkward position of having to pay a bank to hold one's money. Real discount rates for people's real money are often minus numbers. So your ingenious calculation from a $16 price in the year 2000 back to a $1.50 price now, I think, is misleading. On the other hand I think in arguing that Saudi Arabia can have common sense with respect to the year 2000, you have *underestimated* the discount rate for politicians' vision of the future. Very few politicians can see 20 years ahead. Most of them can't see more than four years ahead. Now that's a very high discount rate of future vision. I think if one puts those two factors back into Morry's analysis, which otherwise is one which one has to accept, I think you can come to very different conclusions.

Mr. Adelman:

I'll deal with the second problem first. If indeed the horizon of Saudi politicians is really that short, it makes my own conclusion a great deal stronger. I assumed that they can afford to wait for 25 or 50 years. Jock says they can't afford to wait more than four or five years. That is a much more powerful reason to get the oil out of the ground a great deal faster. So I suppose I have to thank him on that score because I suspect there is a good deal of truth in what he says. Now on the first criticism, which is a good deal more complex, he is quite right that the *risk-free* interest rate in real terms, and real terms is what I was talking about, is very likely in the neighborhood of 3 percent. But I would defend 10 percent as being a proper rate of discount for a highly risky sort of expectation or enterprise. Now risk is an odd subject. There are different ways of allowing for it. For example, I said $16, assuming the use of 1975 technology in the year 2000. Suppose I'd said, "In a world other than our own, in a world which will spend money on research over the intervening time and not waste massive funds on development, which is, of course, what we are probably going to do, the price set by the cost of producing alternatives would be a great deal less than $16." Now had I, say, used $8, it would have been double counting to say $8 discounted by a high-risk rate. What I did was to say $16 and say that all kinds of things *could* happen, some of which are assuredly going to happen. That is why I said a nominal rate would be not 10 percent but 15 or, if Jock wants to push me, I'll make it 17. But for a highly risky venture, 17 percent is hardly excessive, so I think that 10 percent in real terms makes plenty of sense. But now suppose, horrid thought, that I am altogether wrong about this and that it should not be 10 percent real, but only 5 percent real. Then you get a premium, not of $1.25, but of $3.50, some of you probably carry pocket calculators around, can do that, make it then $3.50. Still we are talking about a world which is several miles and many dollars away from the world we live in. So if the price then were $4 — this is still a long way from the $11.50 we have now and the $12 or $15 we are going to have before too long — scarcity won't explain the price and the market with which somehow we have to cope.

Mr. Morris:

Well, we have a schedule permitting about 10 minutes of questions from the floor addressed to either of our speakers. Who would like to lead off?

Mr. Syron:

I have a question about Mr. Ritchie's forecast of increase in total energy supplied by gas that is demanded in your scenarios. It seems rather optimistic.

Mr. Ritchie:

Don't confuse the worldwide situation with the U.S. system. The world does not yet have a Federal Power Commission and therefore it does not have a total disincentive to produce combined with a ridiculous incentive to consume. Substantial amounts of natural gas are being found in many areas of the world — in fact, embarrassingly large amounts in the Middle East, from where it is at the moment barely economic to transport it anywhere else. That is just beginning to become economical. My scenario includes a substantial increase in international trade in liquified natural gas. That's the answer to that question.

The Energy Crisis and New England's Economy

Robert W. Eisenmenger and Richard F. Syron*

I. Introduction

New England's locational disadvantages and paucity of natural resources have shaped its economy. The realities of the region's situation have forced it to concentrate its manufacturing on skill-intensive products with low energy requirements. This paper analyzes the problem of whether the region's manufacturing base can survive present high energy costs.

Part II includes a brief history of the region's economy and shows that the firms that have survived do not require easy access to national markets, low-cost unskilled labor, low-cost fuel and energy or a mild climate. The region's firms now specialize in the manufacture of such products as computers, jet engines, electronics, specialized machinery, medical instrumentation, specialized industrial fabrics and razor blades. In this way, the region's firms minimize their locational disadvantages and maximize the benefits of a pool of inexpensive high-skilled labor.

Part III of our paper demonstrates that even though the region's firms have adapted to their harsh environment by specializing in non-energy intensive products and services, the recent rapid escalation in fuel and energy costs has provided a substantial shock. This shock is likely to be felt most by the region's manufacturers. Even though New England manufacturers do not produce energy intensive goods, they still require more then twice as much energy per employee as services (See Table 1). Part III addresses the question of whether the recent increases in energy costs will allow even nonenergy intensive manufacturing industries in New England to survive. An attempt is made to answer this question by quantifying the competitive burden of recent energy price increases on the total costs of New England manufacturing industries.

*Robert W. Eisenmenger is Director of Research and a Senior Vice President of the Federal Reserve Bank of Boston. He is a long-time expert on the New England economy. His book on *The Dynamics of Growth in New England's Economy, 1870-1964* was published in 1967.

Richard F. Syron is an Assistant Vice President and head of the Regional Section in the Research Department of the Federal Reserve Bank of Boston. He was previously a Deputy Director of the Budget for the Commonwealth of Massachusetts.

Note: Throughout this paper, the electrical component of total energy is on a net basis. Net useful energy is the Btu content of electricity at the point of consumption. It does not include energy losses incurred in the production and transmission of electricity.

Table 1

NET ENERGY USE PER EMPLOYEE IN MANUFACTURING AND SERVICES: NEW ENGLAND AND THE REST OF THE UNITED STATES, 1971
(Mill. of Btus per Year)

	United States (excluding New England)	New England
Manufacturing	738	334
Services[1]	133	155
Total Manufacturing and Services	302	211

[1]Services include finance, trade, construction, government and a great variety of business and personal services.

Source: See Bibliography.

The paper concludes that the crux of New England's competitive problem is that most manufacturing energy in the region is supplied by oil while in the rest of the country natural gas is used. The price of oil has increased substantially since the Arab oil embargo while the price of natural gas has remained relatively low. If New England is to retain any significant manufacturing employment, the prices of these fuels need to be brought closer together.

II. The New England Economy: Its History and Adaptation to High Energy Costs

Few if any regions in the United States have as poor a natural endowment as New England. The region suffers from high power and fuel costs, is far distant from most national markets and has almost no indigenous raw materials. It has little good farmland, a harsh winter climate and high cost unskilled labor. As a result of all these factors, it has a high cost of living. If the west coast of the United States had been explored and developed before the east, it is a fair guess that the settlement pattern of the United States would be entirely different from what it is today. Both California and the Northwest would be substantially more densely populated. The east coast, on the other hand, would have many fewer people and New England might be largely under the administration of the U.S. Park Service.

Despite all its disadvantages New England has been able to remain an important economic region because it has benefited from its head start. It had a mature manufacturing economy by 1860 and each of its six constituent states has grown steadily ever since. Connecticut now has the highest per capita income in the Nation and Massachusetts ranks 16th. Even though the region has only 5.8 percent of the Nation's population, it has 7.1 percent of the Nation's manufacturing employment. How has it been possible for such a poorly endowed region to maintain growth when it is in competition with regions with much lower factor costs? There are a number of partial answers to the question but they all relate to the ability of New England's firms to adapt to their harsh economic climate.

New England now only has a small remnant of the prosperous agricultural economy it had in 1850. Similarly, the region no longer mines its own iron ore as it did in the late 1600s in eastern Massachusetts and in the 1700s in Litchfield County, Connecticut or its own coal as it did in Rhode Island in the 1800s. The region's manufacturing and service sectors, however, have gradually adapted by specializing in industrial processes and types of economic activity which are not handicapped by a poor natural endowment. In the late 1800s and the early 1900s manufacturing firms in this region became labor intensive because they had access to low-cost unskilled labor from the abandoned farms in northern New England and from immigrant labor moving in from Europe. However, the farm abandonment process gradually slowed and in 1920 Federal laws restricted immigration from Europe. Thus, New England was cut off from its plentiful supply of low-cost labor. As a result, the region started its relative decline in manufacturing in the 1920s and this decline accelerated in the late 1940s and 1950s as the Midwest, South and Far West competed successfully.

After the war, New England's economy was extremely vulnerable. In 1947 there were 282,000 employees in the textile industry, 109,000 in the shoe and leather industry, and another 92,000 in the furniture and apparel industries. Altogether, therefore, 33 percent of the total manufacturing employment in the region was in declining industries which were extremely vulnerable to low-cost competition in other regions in the country. The relatively high cost of unskilled labor has been a major competitive disadvantage for firms in these industries, but the costs of fuel and energy were a contributing factor. The result was a drastic recession in New England which lasted from 1948 through 1953. During that entire period the unemployment rate in New England was typically about 1/3 higher than the national average and the unemployment rate in such depressed areas as Fall River, New Bedford, Lowell, and Lawrence often was twice the national average. Gradually, however, New England manufacturing firms did adapt by moving into industries that were high-skill intensive and those that used a relatively small amount of fuel and energy. The adaption was made somewhat easier because, as is shown in Table 2, the relative disadvantage of the region's fuel and energy costs diminished substantially in the period between 1947 and 1971.

Table 2

COST OF ENERGY USED IN MANUFACTURING:
NEW ENGLAND AND THE REST
OF THE UNITED STATES
(Dollars per Mill. Btus)

	1947	1958	1962	1971	1974[1]
New England	.66	.91	1.04	1.15	2.82
United States (excluding New England)	.32	.59	.62	:78	1.22
Ratio of New England to United States Costs	2.06	1.54	1.68	1.47	2.31

[1]Estimated

Source: See Bibliography.

Nevertheless, it is quite clear that those industries which grew the slowest in the postwar period were those that used relatively large amounts of unskilled labor and energy. Thus, the food and kindred products, textiles, leather, lumber and wood products, petroleum, and the primary metals industries all remained relatively stable or declined precipitously. On the other hand, the instrumentation, transportation, electrical and electronic equipment industries all grew rapidly. These industries typically depend primarily on skilled labor and use relatively small amounts of energy.

While New England manufacturing was changing from one type of labor intensiveness to another, U.S. manufacturing was undergoing its own revolution. Between 1947 and 1971 the average annual increase in productivity in U.S. manufacturing was 4.4 percent. These giant strides in productivity permitted a relatively small number of employees to produce the Nation's needed output in energy intensive basic industries such as steel, petroleum, coal and textiles. At the same time, there was a plentiful supply of labor available to produce a rapidly expanding volume of non-energy intensive products.

The preceding paragraphs demonstrated that the United States and New England both moved toward nonenergy intensive production in the postwar period. As Table 3 shows, the revolution was somewhat more dramatic in the Nation. In 1947 manufacturers in the rest of the Nation used 2.86 as many Btus per dollar of value added as did those in New England; by 1971 this ratio had declined to 1.90. However, New England manufacturing as a result of its industrial mix continues to use only about one half as much energy per unit of output as manufacturing in the rest of the Nation.

Table 3

NET ENERGY USE PER DOLLAR
OF VALUE ADDED IN MANUFACTURING:
NEW ENGLAND AND THE REST
OF THE UNITED STATES
(Energy Use in Thousands of Btus;
Value Added in Constant Dollars — 1971=100)

	1947	1958	1962	1971
United States (excluding New England)	91.1	52.1	47.6	44.0
New England	31.9	27.6	21.8	23.2
Ratio of United States to New England Use	2.86	1.89	2.18	1.90

Source: See Bibliography.

Energy Use by Industry

The data in Table 4 indicate that most industries in New England use substantially less energy per dollar of value added than the same industries in the rest of the Nation. This might seem to suggest that firms in New England use substantially less energy per unit of output than do firms producing identical products in other parts of the country. This is not the case, however. If detailed information were available by type of firm for different parts of the country, it would undoubtedly show New England manufacturers to be very similar to their national counterparts in energy use. Detailed information is available on the internal composition of each industry in both New England and the United States. While there are no regional data on energy use for subindustries, such information is available for the Nation as a whole. These data clearly demonstrate that New England specializes in nonenergy intensive subindustries within each broad industry classification.

For example, Table 5 indicates that within the machinery and electrical and electronic equipment industries New England manufacturers tend to specialize in the less energy intensive products. Typewriters, office machinery, and electronic computing machinery account for almost 45 percent of New England's value added in the nonelectric machinery industry. These products require about 5,000 or 6,000 Btus per dollar of value added compared to the industry average of 12,000. Similarly, radio and television communication equipment, the most important New England component of the electrical and electronic equipment industry, requires very little energy.

NET ENERGY USE PER DOLLAR OF VALUE ADDED IN MANUFACTURING: NEW ENGLAND AND THE REST OF THE UNITED STATES, 1971

Industry	United States (excluding New England) Thousands of Btus/$ Value Added	United States (excluding New England) Percent Distribution of Value Added	New England Thousands of Btus/$ Value Added	New England Percent Distribution of Value Added
All Manufacturing	44.0	100.0%	23.2	100.0%
Food and Kindred Products	30.5	11.2	29.1	5.7
Tobacco Manufacturing	7.5	0.9	N.A.	0.0
Textile Mill Products	35.8	3.1	44.1	4.3
Apparel and Other Textiles	5.5	4.0	3.8	3.0
Lumber and Wood Products	36.4	2.2	20.6	1.4
Furniture and Fixtures	11.8	1.7	18.1	1.1
Paper and Allied Products	120.2	3.6	117.8	4.8
Printing and Publishing	5.7	5.7	6.5	6.1
Chemicals and Allied Products	98.8	9.6	35.7	5.1
Petroleum and Coal Products	288.2	1.9	N.A.	0.1
Rubber and Miscellaneous Plastics	24.0	3.0	25.3	2.9
Leather and Leather Products	11.7	0.7	14.1	3.2
Stone, Clay and Glass Products	125.3	3.5	47.5	2.5
Primary Metal Industry	125.1	6.9	43.4	4.4
Fabricated Metal Industry	16.1	7.0	14.9	7.3
Machinery, except Electrical	12.3	9.5	9.2	12.4
Electrical and Electronic Equipment	9.9	8.7	8.5	11.6
Transportation Equipment	11.1	11.4	12.1	7.0
Instruments and Relative Products	8.6	2.4	6.2	6.1
Miscellaneous	10.4	3.1	12.8	5.7

Source: See Bibliography.

Table 5

ENERGY USE AND DISTRIBUTION OF VALUE ADDED FOR SELECTED INDUSTRIES, 1971

SIC Code	Industry	Percentage of Value Added Within Industry Group: United States	Percentage of Value Added Within Industry Group: New England	Thousands of Btus/$ Value Added United States
35	Machinery, except Electrical	100.0%	100.0%	12.0
3531	Construction Machinery	8.3	0.4	15.6
3535	Conveyors and Conveyor	1.4	0.3	8.8
3541	Machine Tools, Metal Cutting	2.4	10.0	12.9
3542	Machine Tools, Metal Forming	1.2	3.4	13.1
3544	Special Dies, Tools, Jigs, Fixtures	4.8	4.3	11.2
3545	Machine Tool Accessories	2.3	7.3	11.0
3551	Food Products Machinery	1.6	1.2	9.3
3552	Textile Machinery	1.3	6.6	15.7
3554	Paper Industry Machinery	0.7	1.9	14.0
3555	Printing Trades Machinery	1.3	3.0	8.4
3559	Special Industry Machinery, nec.	4.2	7.6	10.8
3561	Pumps and Compressors	4.1	1.0	12.1
3564	Blowers and Fans	1.2	0.8	11.3
3567	Industrial Furnaces and Ovens	0.7	0.2	6.3
3569	General Industry Machinery, nec.	2.0	2.1	10.0
3572, 3579	Typewriters and Office Machinery	2.1	13.7	6.2
3573	Electronic Computing Machinery	9.6	30.5	5.2
3585	Refrigeration Machinery	9.3	1.2	14.5
3589	Service Industrial Machinery, nec.	1.3	1.2	11.1
3599	Miscellaneous	8.1	5.6	12.7
36	Electric and Electronic Equipment	100.0	100.0	9.8
3621	Motors and Generators	4.8	0.2	14.7
3623	Welding Apparatus, Electrical	1.2	0.3	13.1
3629	Electric Industrial Apparatus, nec.	0.9	1.7	9.9
3634	Electric Housewares and Fans	2.8	1.0	10.4
3643	Current-Carrying Wiring Devices	2.6	8.0	7.8
3644	Non-Current-Carrying Wiring Devices	1.6	3.1	14.9
3651	Radio and TV Receiving Sets	5.9	3.0	4.7
3661	Telephone and Telegraph Equipment	8.7	1.8	7.1
3662	Radio and Television Communications Equipment	19.0	23.3	5.1
3674	Semiconductors and Relative Equipment	4.7	0.8	10.5
3679	Electronic Components, nec	6.2	7.5	10.8

Source: See Bibliography.

III. Energy as a Competitive Factor for New England Manufacturing, Then and Now

Although most New England firms specialize in nonenergy intensive production, it does not follow that the high cost of energy in the region is not a significant problem for them. As shown previously in Table 2, New England firms have traditionally paid much higher prices for industrial energy than firms in other regions. In 1947 industrial fuel costs in the region were 106 percent higher than in the Nation. Although this disadvantage decreased to 47 percent in 1971, it skyrocketed to an estimated 131 percent in 1974.

The reason for the high cost of energy in New England is obvious. With the exception of a relatively small amount of water power, the region has no indigenous sources of energy. Coal and natural gas, the principal sources of energy in the rest of the country, can only be transported at high cost to the region. As a result, petroleum products particularly residual oil — constitute New England's principal sources of energy (See Table 6). Residual oil is a relatively high-cost fuel in most parts of the Nation, but in New England it is usually the lowest cost fuel available. Since 1971, residual oil costs have gone through the roof. As shown in Table 7, the average price of residual oil in New England increased by 262 percent between 1971 and 1974. In the same time period, in the Nation the cost of natural gas increased only 65 percent and coal rose by 96 percent. Similarly, between 1971 and 1974 the cost of purchased industrial electricity rose by 84 percent in New England because the region's

Table 6

DISTRIBUTION OF NET ENERGY USED IN MANUFACTURING: NEW ENGLAND AND THE REST OF THE UNITED STATES, 1971
(Percent of Total Btus)

	Bituminous Coal and Lignite	Petroleum Products	Natural Gas	Utility Electricity
United States (excluding New England)	19.3%	22.5%	48.1%	10.2%
New England	1.9	58.9	17.6	21.6

Source: See Bibliography.

electric utilities depend on residual oil. In comparison industrial electricity rose only 49 percent in the Nation in the same period. In summary then, New England firms have always had an industrial fuel cost disadvantage which has been exacerbated by the Arab oil embargo and the recent national energy crisis. As a result, industrial energy costs in New England are now in a class by themselves.

It is difficult to quantify the competitive burden imposed on New England firms by the high cost of industrial energy. Obviously, the disadvantage varies by industry. However, Table 8 provides some interesting data for the region's manufacturing compared with the Nation's. In 1971 the cost of energy amounted to 1.4 percent of total shipments of New England manufacturers, somewhat less than the 1.6 percent average for the rest of the country. In 1974, however, the cost of purchased energy is estimated at about 2.6 percent of toal shipments in New England which is much greater than the 2 percent average figure for the remainder of the

Table 7

PERCENT CHANGE IN ENERGY PRICES BETWEEN 1971 AND 1974: NEW ENGLAND AND THE UNITED STATES
(Percent)

	United States	New England
Coal	95.6%	190.6%
Gas	64.9	195.6
Fuel Oil		
Distillate (No. 2)	83.4	80.6
Residual (No. 6)	246.3	262.2
Other Fuels	94.8	232.8
Purchased Electricity	49.2	84.0

Note: Other fuels include gasoline, liquified petroleum gases, wood, purchased steam and coal, gas and oil not specified elsewhere. Since a price index was not available for this category, an average of the indexes of coal, gas and fuel oil was used, weighted by the distribution of these fuel costs to total manufacturing in New England and the United States.

Source: See Bibliography.

Table 8

ESTIMATED EFFECT OF ENERGY PRICE INCREASES FOR MANUFACTURING NEW ENGLAND AND THE REST OF THE UNITED STATES

	Energy Costs as a Percent of Value of Shipments, 1971		Energy Costs as a Percent of Value of Shipments 1974 (Estimated)		Percent Change in Energy Costs per Dollar of Shipments, 1971-74		Percent Distribution of Production Workers	
	United States*	New England	United States*	New England	United States*	New England	United States*	New England
All Manufacturing	1.6%	1.4%	2.0%	2.6%	27.1%	84.4%	100.0%	100.0%
Group 1								
Textile Mill Products	1.6	2.3	2.3	5.0	40.8	117.5	6.1	7.0
Apparel and Other Textiles	0.5	0.5	0.6	0.9	29.2	83.5	9.2	5.5
Leather and Leather Products	0.7	0.8	0.9	1.6	17.7	90.9	1.5	6.7
Paper and Allied Products	3.4	4.3	5.1	9.5	51.0	125.1	3.7	5.6
Group 2								
Lumber and Wood Products	1.9	1.4	2.2	2.1	18.2	55.0	3.7	2.1
Furniture and Fixtures	0.8	1.0	1.2	1.9	39.5	100.6	2.9	1.7
Chemicals and Allied Products	3.3	1.6	4.4	3.3	33.2	105.5	4.2	2.2
Stone, Clay and Glass Products	4.6	2.6	6.4	6.1	38.1	131.7	3.7	2.3[1]
Tobacco Manufacturing	0.4	N.A.	0.6	N.A.	61.9	N.A.	0.5	
Petroleum and Coal Products	2.4	N.A.	1.9	N.A.	-18.1	N.A.	0.8	0.2
Group 3								
Food and Kindred Products	0.8	1.1	0.9	1.6	7.9	41.5	8.6	4.5
Printing and Publishing	0.6	0.8	0.8	1.3	18.0	73.6	4.8	5.1
Rubber and Misc Plastics	1.5	1.9	2.0	3.5	28.3	82.5	3.1	5.5
Primary Metal Industry	4.1	2.1	4.9	3.6	21.1	72.7	7.4	4.5
Miscellaneous	0.8	1.1	1.0	2.2	27.5	95.0	3.2	7.3
Group 4								
Fabricated Metal Industry	1.0	1.2	1.3	1.7	21.9	38.2	7.6	7.8
Electric and Electronic Equipment	0.8	0.9	1.1	1.7	35.4	94.0	8.6	10.5
Machinery except Electrical	0.8	1.0	1.1	1.8	32.7	84.2	9.2	10.3
Transportation Equipment	0.6	0.8	0.5	1.6	40.8	100.4	9.4	7.1
Instruments and Relative Products	0.7	0.6	1.1	1.3	51.6	99.5	1.3	4.2

*Excluding New England

[1]Derived by subtracting other industries from total

Less than .05

Note: See text for a discussion of the characteristics of each group.

Source: See Bibliography.

Nation.[1] Thus, even though New England firms on average use only about one-half as much energy per unit of output as their counterparts in the Nation, energy is still a greater share of manufacturing costs in the region.

Differential Energy Costs by Major Industries

Although the difference in energy costs of manufacturing as a whole between New England and the rest of the United States is interesting, it is not as revealing as comparisons by industries. To provide this more detailed analysis we divided New England's industries[2] into four groups:

1) Declining industries
2) Industries that are not major employers
3) Major employers that are not high technology industries
4) High technology industries

Group 1 — The Declining Industries: Textiles, Apparel, Leather and Paper. Although these industries have been declining for some time, they still supply about one-fifth of New England's manufacturing employment. In each of them energy costs as a percentage of shipments increased by at least three times as much in New England as in the rest of the country between 1971 and 1974. Energy costs are not a substantial share of total costs in the leather or apparel industries and thus will have little impact in determining their competitive position in New England. Energy costs are extremely important, however, in the textile industry. As shown in Table 8, in New England energy costs as a percentage of shipments are estimated to be 5.0 percent as compared to 2.3 percent in the United States. The region's textile industry declined sharply after World War II but has stabilized somewhat in recent years. Nevertheless, it is extremely vulnerable. If the present wide differential in energy costs between the region and the Nation persists, it seems likely that this industry will continue to decline.

[1]The competitive impact of increased energy prices on New England was estimated by updating the 1971 data on purchased fuels and electricity as a percentage of shipments. The estimated 1974 cost of purchased fuel and electrical energy was obtained by multiplying each industry's fuel mix on a state-by-state basis by New England price indices. National price indices were used to update shipments. Since these data do not reflect fuel conservation or changes in production processes brought about by higher fuel prices, they may slightly overstate the increase in energy costs as a share of total costs. However, the magnitude of the changes is so great that even if such an adjustment were possible, it would be unlikely to change the conclusion that the 1971 to 1974 increase in fuel prices has caused the region significant competitive injury. Arthur D. Little, Inc. has estimated that in almost all cases energy use per unit of output has decreased by a little less than 10 percent. See *Preliminary Projections of New England's Energy Requirements*, Arthur D. Little, Inc., prepared for the New England Regional Commission, November 1974.

[2]Energy costs as a percent of shipments are not available for the New England segment of two industries, petroleum and coal products, and tobacco manufacturing. Accordingly, 18 industry groups are analyzed.

Energy costs are even more important for the pulp and paper industry than for the textile industry. Unfortunately, high cost residual oil is the industry's most important fuel source in New England. As a result, energy costs increased faster for the region's paper manufacturers than those for their competitors elsewhere and are now estimated to be almost 10 percent of shipments. This compares with about 5 percent in the rest of the United States. Thus, current energy costs of New England paper manufacturers seems likely to further erode their competitive position.

Group 2 — Non-major Employers: Lumber, Furniture, Chemicals, Stone, Glass and Clay. While energy costs increased more in New England than elsewhere in this group of industries, none of them is a major regional employer. The New England segment of most of these industries is also not energy intensive. However, taken together these industries supply about 9 percent of the region's manufacturing employment and if energy costs remain substantially higher in New England than elsewhere, some employment loss could result.

Group 3 — Major Employers Which Are Not High Technology Industries: Food; Printing and Publishing; Rubber and Plastics; Primary Metals, and Miscellaneous Manufacturing. These industries do not fit neatly into any one classification. For our purposes, however, they have several similar characteristics: each industry accounts for more than 4 percent of manufacturing employment in the region; in recent years, their fuel costs increased substantially more here than in the Nation; and in general they cannot be considered high technology industries.

For food and kindred products as well as for printing and publishing, the recent rapid rise in energy costs may not have any significant impact on employment. Since these industries primarily serve local and regional markets, they are not vulnerable to lower-cost competition from other regions. However, the recent escalation in their fuel costs has raised prices for individuals and industries that buy their products.

The region's rubber and plastics industry has suffered substantial employment losses in recent years. In some cases plants have been abandoned in favor of new installations in other parts of the country where unskilled labor costs are substantially lower. Lower energy costs and lower raw material costs are important attractions in other regions. For example, the plastics segment of this industry uses a substantial amount of energy as well as petroleum feed stocks. As shown in Table 8, energy costs in this industry as a percentage of shipments amount to 3.5 percent in New England as compared to only 2 percent in other parts of the Nation. This 1 1/2 percent differential constitutes a significant disadvantage which will put substantial competitive pressure on New England firms in this industry.

Group 4 — High Technology Industries: Fabricated Metals; Electric and Electronic Equipment; Non-electrical Machinery; Transportation Equipment and Instruments. Most of these industries have been growing in the postwar period in New England and now provide about 40 percent

of the region's manufacturing employment. They have remained competitive by producing high value products that require little energy and depend on New England's pool of skilled labor. Although energy still remains a fairly low share of total costs in high technology industries in New England, the impact of the increase in energy prices from 1971 to 1974 is far from insignificant.

For example, as a result of energy price increases, energy costs now amount to 1.7 percent of the shipments of New England electric and electronic producers as compared to 1.1 percent in the rest of the Nation. This is true even though New England manufacturers use substantially less energy than those in the rest of the Nation. In effect, these New England firms are paying about twice as much per Btu as are their competitors in the rest of the country.

In order to get some measure of the importance of this energy cost disadvantage, it is useful to compare it with another of the region's disadvantages — high state and local tax burden on businesses. The Pennsylvania Economy League estimates that state and local taxes are equivalent to about 1.26 percent of the average Massachusetts electrical equipment producers' sales. This tax burden is only 10 to 20 percent higher than in most other industrial states.[3] Thus, energy costs are now obviously a much more important disadvantage than state and local taxes for this industry.

A similar pattern holds for the non-electrical machinery industry. Purchased fuels and electricity are estimated to be equivalent to 1.8 percent of shipments for New England's non-electrical machinery producers. State and local taxes were estimated to equal 1.7 percent of sales.

To maintain any manufacturing base at all, New England must hold onto such non-energy intensive high technology industries. By itself, an energy cost differential which is equivalent to less than 1 percent of shipments is not likely to cause any great employment loss in the short run. But over the longer run when firms have more freedom to relocate in order to minimize costs, New England's new energy disadvantage, when added to the region's other cost disadvantages, could have a very substantial impact.

IV. Conclusions and Policy Implications

It is impossible to completely eliminate New England's competitive disadvantage in fuel costs. Exploration for oil and gas in the Georges Bank and possibly for coal in the Narragansett area may result in some

[3] *Comparative State and Local Tax Burdens on Business*, Pennsylvania League for Economy in Government, 1972. These data are for total state and local taxes but do not include unemployment insurance levies. If these levies were included, Massachusetts' competitive disadvantage would be more severe.

new energy sources and should be encouraged. However, most of the region's energy will still have to be imported from other parts of the country and the world. The crux of New England's competitive problem is that most manufacturing energy in the region is supplied by oil while that role is filled by natural gas in the rest of the country. The price of oil has increased substantially since the Arab oil embargo while the price of natural gas has increased much less. At the present time natural gas costs about $.50 per million Btus at wellhead while residual oil costs about $1.75 per million Btus delivered at major ports.[4] Therefore, any actions taken to equalize gas and oil prices will work to the region's competitive advantage.

Conceivably, oil prices could be brought closer to the price of natural gas by stringent price controls. However, it is impossible to impose such regulations on residual oil which is mostly imported and therefore not subject to domestic price controls. Most New England manufacturers rely heavily on residual oil.

The most direct way to equalize the cost of energy for manufacturing between New England and the rest of the United States would be a phased deregulation of natural gas prices. Allowing the price of natural gas to rise would increase the energy costs of manufacturers elsewhere, thereby improving New England's competitive position. This action would not impinge on the welfare of the rest of the Nation. New England's improved competitive position would be incidental to the primary benefit of deregulation — increased gas supplies and more efficient use of a premium fuel.

The price of natural gas sold in interstate commerce has been regulated by the Federal Power Commission (FPC) since 1954. Price ceilings set by the FPC became binding in the late 1960s when the demand for gas at the low regulated price started to outstrip supply. Since then there has been an ever increasing shortage of natural gas. Gas shortages are more pronounced in the interstate market than in states with their own supplies where gas sells for as much as four times the FPC interstate ceiling price. Price ceilings established by the FPC have had an effect similar to the Arab oil embargo on areas without their own supplies of natural gas. Newly discovered natural gas is increasingly being made available only in the South and Southwest. In the long run, the effect of current policy will be to force many manufacturers to locate in these gas-producing states.

Bringing intrastate sales under regulation has been proposed as one possible solution. However, there are problems with this approach. Putting price ceilings on intrastate sales would only tend to perpetuate an artificial difference in the cost of energy produced by gas and other fuels.

[4]Because of differences in transportation costs to the ultimate users prices may be considerably closer in some locations.

In many ways, gas is a premium fuel with uniquely valuable characteristics and should be reserved for uses where it is most essential. The present pricing structure for gas subsidizes its use in applications where other fuels could be used just as well. For example, gas is used to produce electric power in the Southwest. If the price of gas were allowed to seek its market level, its use would tend to be reserved for industrial applications such as drying where it is uniquely valuable.

A more serious criticism of further regulation is that it will discourage exploration. The FPC has estimated that even under present regulations demand will exceed supply by 30 percent by 1980.[5] Independent experts have also estimated that deregulation would largely eliminate the natural gas shortage by that time.[6]

While decontrol would be advantageous to the Nation and of particular benefit to New England, it would not be painless. Decontrol would result in higher energy prices to most natural gas users at least in the short run. However, in New England most natural gas is used for residential purposes and the price of the fuel at wellhead comprises only about 15 percent of the cost of residential gas service. Thus a substantial increase incurred in wellhead prices would not greatly increase the cost of gas for home heating.

Moreover, in the long run, decontrol could reduce energy costs to many gas users. As a result of an inability to obtain sufficient supplies in the interstate market, many gas distributors have had to rely increasingly on expensive liquified and synthetic gas. For example, this year some New England utilities were forced to purchase liquified gas at more than three times the price of ordinary natural gas.

By encouraging exploration, deregulation would also make more gas available to substitute for higher cost fuels. Paul MacAvoy, of the Council of Economic Advisers, has estimated that the increase in the supply of gas brought about by deregulation will result in a 1 million barrel a day reduction in residual oil demand.[7] This development would be particularly beneficial to this region.

Deregulation of natural gas is one issue where the interests of New England coincide with those of the rest of the Nation. However, immediate complete deregulation may not be politically feasible or desirable. Sudden decontrol could subject the Nation to a resurgence of inflationary pressure at a highly inopportune time. Phased decontrol allowing prices on new natural gas to be determined by market forces by 1980 could avoid some of these problems and still yield many of the benefits of complete deregulation. If this is not possible, gas prices should at least be allowed to increase much more than they have been in the past.

[5]FPC Bureau of Natural Gas, *Natural Gas Supply and Demand.*

[6]Paul W. MacAvoy and Robert S. Pindyck, *Price Controls and the Natural Gas Shortage*, American Enterprise Institute for Public Policy Research, Washington, D.C., 1975, Chapter 4, p. 31.

[7]*Ibid.*, p. 53.

BIBLIOGRAPHY

American Gas Association. *Gas Facts.* 1961, 1963, 1971. (Table 1)

American Petroleum Institute. *Petroleum Facts and Figures.* 1971. Baltimore, May 1971. (Table 1)

Edison Electric Institute. *Statistical Year Book of the Electric Utility Industry for 1971.* No. 39, Publication No. 72-25. New York, October 1972. (Table 1)

________________. "Analysis of Fuel for Electric Generation by the Electric Utility Industry: Fuel Burned Under Boilers and by Internal Combustion Engines." New York, 1974. (Tables 2, 7, and 8)

Electric Council of New England. *Electric Utility Industry in New England. Statistical Bulletin,* 1970, 17th Edition, July 1971. (Table 1)

Federal Power Commission. "Monthly Report on the Cost and Quality of Fossil Fuels Delivered to Steam-Electric Utility Generating Plants." *FPC* News, 1971-1975. (Tables 2, 7, and 8)

________________. Bureau of Natural Gas. *Natural Gas Supply and Demand, 1971-1990.* Washington, D.C., 1972.

MacAvoy, Paul W. and Pindyck, Robert W. *Price Controls and the Natural Gas Shortage.* American Enterprise Institute for Public Policy Research. Washington, D.C., 1975. Chapter 4, p. 31.

U.S. Bureau of the Census. Census of Manufactures: 1947, Vol. I, *General Summary.* Vol. III, Statistics by States, and MC203, *Fuels and Electric Energy Consumed.* Washington, D.C., 1950. (Tables 2 and 3)

________________. Census of Manufactures: 1958. Vol. I, *Summary Statistics.* Vol. III, *Area Statistics.* Washington, D.C., 1961. (Tables 2 and 3)

________________. *Annual Survey of Manufacturing:* 1962. Washington, D.C., 1964. (Table 3)

________________. Census of Manufactures: 1963. *Fuels and Electric Energy Consumed by Manufacturing Industries: 1962.* Series M63(1)-6. Washington, D.C., 1964. (Tables 2 and 3)

________________. *Annual Survey of Manufactures: 1970 and 1971.* Washington, D.C., 1973. (Tables 3, 4, 5, and 8)

________________. Census of Manufactures: 1972. Special Report Series: *Fuels and Electric Energy Consumed* and *Supplement.* MC72(SR)-6S, Washington, D.C., 1973 and 1974. (Tables 2, 3, 4, 5, and 8)

U.S. Bureau of Mines. *Minerals Yearbook, 1958,* Vol. II, *Fuels.* Washington, D.C., 1959. (Table 1)

________________. *Minerals Yearbook, 1962,* Vol. II, *Fuels.* Washington, D.C., 1963. (Table 1)

________________. *Minerals Yearbook, 1971,* Vol. I. *Metals, Minerals, and Fuels.* Washington, D.C., 1973. (Table 1)

________________. *Mineral Industry Surveys.* "Sales of Fuel Oil and Kerosine in 1971," October 5, 1972. (Table 1)

________________. *United States Energy Fact Sheets, 1971.* Washington, D.C., February 1973. (Tables 1 and 6)

U.S. Bureau of Labor Statistics. *Employment and Earnings States and Areas 1939-72.* Bulletin 1370-10. (Table 1)

________________. *Employment and Earnings,* United States, 1909-1972 Bulletin 1312-9. (Table 1)

________________. "Retail Prices and Indexes of Fuels and Utilities." 1971-1975. (Tables 2, 7, and 8).

________________. "Wholesale Prices and Price Indexes." 1971-1975. (Tables 2, 7, and 8)

Discussion

Paul A. London*

New Englanders have always known that their region had an energy cost problem. Recently, however, economists have begun to probe more fully the nature of that problem. Robert Eisenmenger and Richard Syron have made an important contribution to our understanding of it with their paper, "The Energy Crisis and New England's Economy." I have no major point to add to what they have said and supported; indeed, I have made similar points to more limited audiences and am glad to see that their more complete analysis supports my position. I would like, however, to add a few shadings to their thesis, which I think help to put it in perspective.

First, in my view, our regional energy dilemma grows out of U. S. energy policies of previous decades. I would argue that the inconsistencies of U. S. energy policy during the 1960s are at the root of New England's disproportionately high energy prices rather than recent developments with respect to the OPEC oil cartel. Recent developments have exacerbated our price disadvantage severely because they have highlighted inconsistencies in the policies developed during the 50s and 60s.

The two cornerstones of our national energy policy during the 1960s were the Mandatory Oil Import Quota Program (MOIP) (1959-1973) and Federal Power Commission regulation of the wellhead price of natural gas (1954 - to the present). Of vital importance is the fact that the two programs had opposite effects on prices. One was a price support and the other a price control mechanism. The MOIP kept the U.S. price of oil above world "free market" levels while wellhead price regulation of natural gas kept natural gas prices below the prices of alternative fuels in many areas of the United States. From a political point of view, the MOIP was a victory for producer interests and natural gas regulation (made possible by Presidential vetoes in 1950 and 1956), a triumph for consumers. In fact, the Eisenmenger-Syron data and material developed in my office suggest that New England would have been far better off if these two policies had moved consistently in the same direction, even if this had meant high prices for gas as well as for oil.

*Director of the New England Economic Research Office in Washington and Economic Advisor to the New England Congressional Delegation. Previously he was associated with the Professional Staff of the Senate Banking, Housing and Urban Affairs Committee as well as various other organizations concerned with economic development.

New England leaders in the Congressional delegation and in the business community (for example, the New England Council for Economic Development) focused on the Mandatory Oil Import Program as the key to New England's energy dilemma from its inception in 1959 until its demise in April 1973. They did this for good reason. The President's Task Force on Oil Import Control in 1970 suggested that the cost to the nation's consumers of higher oil prices as a result of the MOIP was $4.8 billion per year, about $400 million of which fell on New England. On a per capita basis, New England bore much more than a fair share of the burden.

Eisenmenger and Syron show conclusively, however, that the MOIP and high oil prices were only one blade of an energy price scissor which gave New England disproportionately high energy costs. Because of FPC regulation, the tendency which would normally have operated for MOIP-established oil prices to pull up natural gas prices in other regions was greatly weakened. For example, while oil was selling in New England for 35¢ per million Btus in 1960, natural gas was available in Chicago and Minneapolis for 28¢ or less and in Houston for 19¢. During the next ten years oil prices actually fell due to the ending of import restrictions on residual oil in 1966, but FPC regulation kept natural gas prices from approaching those of oil in most markets.

An interesting question is whether New England would today be in a better position with respect to energy costs had her business and political leaders linked their strong fight to end the MOIP to a similar battle to obtain price parity between natural gas and oil. For fairly obvious reasons, neither New England's gas industry, economists nor politicians by and large saw the region's interests in this light. Instead, many New Englanders who used "free market" arguments against the MOIP supported Federal regulation of natural gas prices. Similarly, many in the producing states who supported the MOIP and who, therefore, defacto favored government price support for oil, wanted the Federal Government to take a hands-off position on natural gas. Almost despite themselves, energy-producing states seem to have gained from their failure to achieve deregulation of natural gas because cheap, easily obtainable gas became a major incentive for industry to locate in these areas. On the other hand, New England, which generally, if not unanimously, supported Federal regulation, seems to have paid a high economic price for its victory.

Now that the New England energy cost problem is better defined and we see that it is not an oil but an interfuel problem, there is still a question as to whether the future development of the region is endangered by the fuel cost differential. Some will argue that the cost differential, although much wider now than at any time since World War II, is less important than before. Eisenmenger and Syron imply that the problem of higher energy costs is important. I certainly believe that it is, but I think this point has to be made with full regard for nuances and possible counter-arguments.

Those who argue against us could take several tacks. One is that no matter what the regional problem, it is morally wrong to support higher natural gas prices. The argument would go that New England's energy costs are admittedly only part of the region's competitive problem and that most New Englanders were following the right path during the 1960s in fighting to lower oil prices without regard to the "subsidy" which price controls on natural gas conveyed to competitors in other regions. They should continue to fight for the lowest possible oil and gas prices.

The problem with this approach as a practical strategy is that there is no possibility of lowering oil prices to anything like the current price of natural gas. While this might have been a possibility during the MOIP days in the 1960s, it is not today. The average delivered price of natural gas to utilities and large industries is now the equivalent of about $3 per barrel of oil. The oil pricing bill passed on September 23 by the House of Representatives (HR 7014) would do no more than roll some domestic oil prices back to $8.50 or so a barrel, leaving oil, which New England relies on, two or three times more expensive than gas. And this bill has little chance of becoming law.

Another argument against the Eisenmenger-Syron position is that the regional energy price differential is less important now because the marginal prices of gas and oil are nearly equal. That is to say, it is impossible for firms to flee high energy cost regions like New England and to find low cost gas or other fuels elsewhere. For example, if a plant moved to Texas or another gas-producing state, it might be able to get natural gas, but only at high intrastate prices roughly equivalent to the price of oil in New England, and even this supply would now be available only on short-term contract. Similarly, in Illinois, Minnesota, or South Carolina in the interstate market low-cost interruptible gas is a thing of the past and little if any gas is available on a non-interruptible basis, and certainly not on long-term contract. Indeed a firm moving from New England to these areas most likely would have to buy oil not gas and at prices as high as those in New England, and perhaps with even less assurance of supply.

This is an important counter to the position which I share with Eisenmenger and Syron. I do not think it is a valid counter, however, for at least three reasons. First, Eisenmenger and Syron do not contend that "marginal" costs for new plants are as out of line as are average energy costs, region to region. High energy costs in New England mean that during periods of slack demand, such as we are now facing, companies with production plants in many parts of the country phase down their New England operations first. This may account for a significant part of our region's dreadfully high unemployment. Similarly, in industries like textiles, where New England companies must compete with companies in other areas, the companies in other regions which still have gas on long-term contract (and this means the majority of firms) have important competitive advantages. This may not affect new plants, but it does affect the region's overall economic performance.

Second, location decisions on new plants are no doubt affected by the kind of problem outlined above, albeit indirectly. High costs in large areas of New England's economy have an impact on the costs of government and of private goods and services bought locally. Thus, although a new plant in Texas or Illinois may not get energy any cheaper than in New England, the underlying impact of higher energy costs raises other costs of doing business in the region. The degree to which this is the case is unclear, but there must be a "ripple effect" from higher regional energy costs which is serious and which ought to be examined and understood by regional economists. I assume, for example, that these indirect manifestations of higher energy costs show up in the price of all services in the region including government, and in the cost of living generally, which probably has a major impact on wages.

Third, it is widely understood that management impressions and prejudices play a major role in locational decisions. New England's historically high energy costs contribute to a negative view of the region as a place to do business even though "marginal" energy costs in other regions may not be much lower than in New England. Moreover, even at the margin a cost disadvantage does exist, which is spotlighted by dramatically variant average costs.

I conclude from this that it is important for economists in New England to make the point that the region's competitive position is determined not by the absolute price of oil but by the price of oil relative to other fuels. Political and business leaders understand this well enough when it is a question of the cost of government, welfare, or wages, but the point that energy costs must be seen in the same way has not been widely appreciated. Eisenmenger and Syron make this point, and I hope that others will study their arguments and, if they agree as I do, incorporate them into their thinking and teaching.

Discussion

James M. Howell*

I would like to make five brief points on the Eisenmenger-Syron paper and also add three observations of my own. Point number one: I think that the paper does correctly note, but does not emphasize quite enough, that the evolution to higher value-added production and lower operational cost has been going on for quite some time because of unemployment compensation, workmen's compensation, property taxes, transportation costs and so on. For example, my own analysis of factor shares based on the 1963 and the 1967 Census of Manufactures indicates that this shift has occurred even in labor-intensive industries. Certainly in our high technology industries there has been a very dramatic swing away from using labor and other substitutable factors of production and trying to the greatest extent possible to increase the value added, attributing most of it to capital. The fact that this has been a long-term trend which was further accentuated by the OPEC embargo is somewhat overlooked in the paper.

Point number two: One thread that runs through the Eisenmenger-Syron paper — and which I consider fallacious — is the frequent reference to phrases such as "locational disadvantage" in New England or "distance from most national markets." I strongly disagree with this line of thinking although I hear it expressed constantly when talking to businessmen, labor leaders, and others involved in formulating economic policy in New England. To be sure, over the past few decades a considerable amount of spatial redistribution of industry has taken place, but it is important to keep two factors in mind. First, the day of the long-haul industrial migration is over. This conclusion is based on my own analysis and has been subsequently confirmed after talking to numerous chief executive officers and businessmen since my joining the Bank; I think that the increased complexity of the production process and the always troublesome problem with management make the geographically dispersed company difficult to manage. The problems of managing people and processes are becoming sufficiently complex so that there will be an increasing tendency for the present distribution of industry to more or less remain where it is.

*Senior Vice President and Chief Economist, First National Bank of Boston, also Director of the Business Research Department and Editor of the Bank's *New England Report*. He has had a wide range of professional experience in university teaching and government, including serving as an economist for the Board of Governors of the Federal Reserve System.

Secondly, I would underscore the geographic consideration, that market access is the key to profitability for a firm. Even with the pattern of spatial redistribution, the Atlantic seaboard states from New England down to Virginia have about $350 million of personal income each year. Now, for those of you who know a little bit about personal income, that's about one dollar in three in the economy as a whole and all within about a 24-hour radius of Worcester, Massachusetts. I, personally, think the Eisenmenger-Syron paper is mistaken in feeling that the action is in Texas or Idaho. It is still very much on the Atlantic seaboard and we in Massachusetts are still very much in the thick of it.

Let me put this thought in another way. The area from New England down to Washington, D.C. represents roughly the combined income of France and Germany. So despite the industrial migration, I submit that we are indeed still where the action is and a lot of the migration that occurred went to Atlanta, Mississippi, Kentucky and Tennessee in order to sell back into this rich eastern market.

Point number three: I agree absolutely with the paper's principal conclusion that although most New England firms specialize in nonenergy intensive production, it does not follow that high energy costs are not a significant problem for them. Let me go over that statement again because it is a classic example of the negative kind of Federal Reserve writing. The statement is, and I will read it, "Although most New England firms specialize in nonenergy intensive production, it does not follow that high energy cost in the region is not a significant problem." Why don't we start saying some things positively? I do think that this statement is interesting and I agree with it; I shall refer to it again later on.

Now, let me talk about my bank's capital spending survey. The Boston Federal Reserve Bank abandoned the original survey in 1968 and my Bank reinstituted it in 1971. It is a regional capital spending survey of manufacturers patterned after the McGraw-Hill survey. We also carried out special energy surveys in the spring of 1974, the fall of 1974 and again in the fall of 1975. According to our survey, in the 12-month period following the OPEC oil embargo, median energy costs in New England manufacturing firms went up 50 percent, and one firm in five had energy cost increases of over 100 percent, and some were as high as 400 percent. Admittedly, energy costs are less than 5 to 7 percent of total cost but when energy costs are rising about 100 percent or so, your total cost is going up 5 percent. Those of us in banking and finance know that the return on stockholders' equity is probably not much more than 5 to 7 percent; therefore, energy increases are wiping out a tremendous portion of the overall profitability of firms. This has really hurt.

Point number four relates to high technology industries. These industries clearly hold a key to our future. The paper mentions SIC codes 34 through 38; I would add 39 because I think it includes some important miscellaneous manufacturing industries. The paper is correct about the energy impact on these industries and also correct, in my opinion, to suggest that we must do everything we can to maintain these industries in New

England's economic base if we are to have a manufacturing base at all. But I'm somewhat troubled about our ability to hold these industries here. The data from our 1975 capital spending survey, based on 356 replies, have not yet been released, but what we have already processed suggests two troubling conclusions.

One of the survey questions asked was "Are you intending or do you intend to cut back your capital spending because of high energy costs?" Eight of the 18 firms indicating they were cutting capital spending because of higher energy costs were in the high technology SIC codes. I think that may be very significant. Then consider the second conclusion, which was in response to question six, "Do you have a planned reduction in your New England operations because of energy costs?" Of the 20 firms that answered they were going to cut back production because of higher energy costs, 10 were in the high technology industries, or again in SIC codes 34 through 39. That is disturbing in terms of our ability to hold these industries and suggests that we need to do more work in digging into their exact nature and which four- or-five digit SIC codes they represent.

Point number five: I do support, as everybody does, controlled deregulation and I offer several conclusions, some of which Paul London has presented more eloquently than I. First, the price of natural gas in Dallas today is higher than in Boston. Second, the rapid increase in natural gas prices in states which produce natural gas has already induced a fairly substantial move away from burning natural gas to reliance on residual oil for generating electricity.

A good example of the trend is the substantial equity position that Mid-South Utilities in Louisiana has taken in the Northeast Petroleum refinery now under construction in Revere, Louisiana in order to be assured of the output of residual oil. The other fact that has not often been mentioned is that the old oil versus new oil issue in time will mean that we will have only new oil, which will be much closer to the world price. That's equilibrating market prices in the right direction. This concludes my comments on the Eisenmenger-Syron paper.

Now I would like to make three comments which reflect my own prejudices. The first relates to our special survey of capital spending. One of the questions we want to address, now that we have collected three data points since the embargo during the fall of 1973, is whether the data suggest perceptible trends in the reduction or increase in capital spending or in firms leaving the region. Briefly, I will summarize the data from spring 1974, fall 1974, and fall 1975. (We did not take a survey in the spring of 1975.) The percent of firms reporting no change in capital spending because of higher energy has remained singularly unchanged: 84 percent six months after the embargo; 83 percent 12 months after, and 82 percent 24 months after. This is interesting; it seems that in the face of their avowed assessment that the energy cost problems have their own sting.

All three surveys also show virtually no change in those firms decreasing capital spending because of increases in energy costs: about 5 to 6 percent in all three surveys. The slight swing from 84 to 82 or no change

was all picked up in an increase in capital spending. For example, in the spring of 1974 only 5 percent of the firms indicated that they were increasing capital spending because of higher energy costs and in the fall of 1975, the survey we are looking at now, this number rose to 8 percent. That's probably statistically insignificant, but it's worth noting that it is rising and not declining. We've done a bit of callback to find out why these firms were increasing capital spending to verify this often articulated view by many of my good friends, the web-footed environmentalists, that they're becoming more energy efficient. We found that not to be true. Most of the firms that are increasing capital spending are buying additional large storage tanks to hoard residual oil!

But my next comment involves the response to question six on our questionnaire, "Do you have a planned reduction in your New England operations because of energy costs?" Here again, it seems to me, the data are rather interesting because overwhelmingly the firms are showing no tendency to scale back their operations in New England due to higher energy costs. If they were starting to do so, we would have seen a more discernible pattern than we have so far.

We did see a slight shift in the fall 1975 survey, two years after the embargo. For example, 97 percent of the firms said "no reduction" six months after the embargo in the spring of 1974. In the fall of that year, 96 percent said "no reduction" in their operations and then in the fall of 1975, 24 months after the embargo, it was 93 percent. That accounts for the drop of three percentage points. We are concerned, as one would suspect, that the planned reduction has doubled from the spring of 1974 to the fall of 1975, from 3 to 7 percent. That's in the wrong direction, but I must say my prior expectations were that it would be far more than that when we started the survey two years ago.

My final observation is actually a more impressionistic conclusion that I could not have made had I not seen the economy in the United States and certainly in New England recently from two rather distinct vantages: one based on eight years in the Federal Government and the other on five years at the First National Bank of Boston. As a consequence of seeing the world from two realities I am persuaded that economists, particularly those in the Federal Government, certainly those in the Federal Reserve System, and often those of the academic variety, really don't fully understand the business and labor realities of our economy, primarily because they have little, if any, contact with the business and organized labor communities. Thus, it is not terribly surprising to me that the Eisenmenger/Syron paper reaches the conclusion that firms ought to leave New England because something in partial equilibrium theory suggests that they will do so.

In actuality they are not leaving, and I'm wondering why not. Over the years I talk to literally hundreds of chief executive officers from all over the region and all over the United States for that matter and they tell me they do feel the pinch of higher energy costs. They know that because they know what the bottom line looks like. But what is surprising is that most New England chief executive officers — aside from the few who are associated with extraordinarily large companies — know very little about relative regional costs. Even when they do perceive relative differential costs they are ponderously slow in accepting these facts and acting on them.

In conclusion, let's see if we can stand back and take an overview of the Eisenmenger-Syron paper. I think it is a classic example of all Federal Reserve Bank papers — it is written in a library, of course. It represents that overedited variety of the fear of saying something important; I remember well my two and a half years at the Board of Governors. Yet in the final analysis my real concern today and my earnest admonition and plea to you is that we are faced with the extraordinarily difficult task of trying to understand the future of the New England economy. In the final analysis I suspect that the data that will allow us to unravel the complexities that we've been talking about for the last several years do not exist today.

In the decade ahead we will be creating and collecting data that in the past decade we never dreamed we would even have to be concerned about. Our surveys at the First National Bank of Boston are examples of this. But we need even more data. We need data that we have never collected before, and we very much need the Boston Federal Reserve Bank's help in collecting these data.

In early 1972 I was involved in the creation of the New England Economic Project, called NEEP, a regional data bank which the Federal Reserve Bank of Boston so generously supplied with data. Yet that Bank has shown absolutely no interest in joining the Project. My admonition is let's get the Boston Federal Reserve out of the library and get it to help us in the business community to get to work to solve some of these real world problems.

Responses to Howell and London

Robert W. Eisenmenger and Richard F. Syron

Eisenmenger

Paul London was very generous in his comments since we used many of the ideas that he has been promoting for the past two years. To his credit he advocated natural gas deregulation several years before it became popular. He has done the kind of research that all of us hoped a professional economist would do for the New England congressional caucus.

As for Jim Howell's comments about New England's economic geography, it is true that we are on the northern tip of the eastern seaboard megalopolis where one-third of the Nation's GNP is produced. It does not follow, however, that our economic geography favors us relative to Pennsylvania, West Virginia, Virginia or many other states. The fact is that the southern portion of that megalopolis has many competitive advantages that New England does not have. States in the southern portion have the same access to that full eastern seaboard megalopolis as does New England, but they have lower energy costs, much lower wage rates for unskilled people, and much better access to the central part of the United States. If you take a look at the electrical machinery industry in New England, you'll find that we don't produce a single washing machine, refrigerator, or dryer. If you're going to produce bulky or heavy consumer products for the whole eastern seaboard megalopolis as well as for the interior of the United States, you simply can't afford to locate in New England. You have to locate either in the middle or the southern part of the eastern seaboard's megalopolis or in our industrial heartland in states such as Ohio or Illinois. New England manufacturers are forced by the facts of life to specialize in skill-intensive, high value-added industries because we have numerous other locational disadvantages.

Of course, Texas is not centrally located. But Texas has numerous advantages other than low-cost energy which include low-cost minerals, labor, and a mild climate. That state also has a low cost of living.

Syron

I had planned to talk about some of Paul London's more moderate comments first but I would like to switch and take the bull by the horns — Jim Howell. I am glad to see that Jim's survey supports our findings. Jim's right; there are problems with the published data we used. However, our study is based on complete information from the Census of Manufactures. If the information from Jim's sample of 3 percent of the manufacturers in New England support it, well, I think that says something for his survey. However, I continue to have more faith in complete data than a small sample.

As far as New England's traditional locational disadvantage goes — people tell me all the time that they don't know how Jim Howell has time to do any research (since he runs around so much) and now I know he doesn't do it by reading; he looks at maps. As I stand here and look out the window at all that ocean, I can't help but think that although we are in the midst of what Jim says is the gold belt of this country, it's going to be awfully hard to produce many washing machines on Martha's Vineyard to sell them to the fish, unless we can get someone who is as good a salesman as Jim is. I think I'll leave Bob Eisenmenger to make some comments on his criticisms of our editorial process; it may actually be helpful.

As far as Paul London's critique, his comments about our paper being based on average costs rather than on a marginal basis may have been too easy on us. Our paper is based on average cost data because that is the only available information. I think, however, that if you made a careful reading of the incentives for people to relocate based on marginal costs that, unfortunately, some of the conclusions you would reach would still be much the same. For example, in the electronics industry, 70 percent of the total cost of purchased fuel and energy is for electrical energy. While it is true, if an electronics company decided to expand, say, in New Mexico rather than in New England, that it might not be able to get a lot of natural gas down there, it still could get relatively low-cost electrical power, produced either by coal or by natural gas. Electricity is the most important component of energy costs for many of these high-technology industries. So it's a little bit more complicated than it might seem at first.

Another point that I talked to Paul about, so I'm sort of stealing his thunder on it, is that in many cases, particularly in the kind of recession that we have just had, a company that has plants in many parts of the country has to make decisions about where to close down and where to expand. In that case, they are more likely to look at the average cost of running plants in different parts of the country.

Financing Difficulties of the New England Electric Utilities

Lynn Browne

In 1974 construction of some 235 electric power plants was postponed or cancelled.[1] In part these deferrals were the result of revised demand projections but for many utilities they reflect an inability to generate substantial funds internally or raise outside capital at an acceptable price.

This paper examines how New England fared in the recent crisis, focusing on the eight largest investor-owned utilities which account for over 96 percent of the region's generation.[2] Part I discusses the general industry problems of massive capital requirements, dependence upon external funding and the erosion of the ability to attract these investment funds. Part II considers the New England experience showing how these problems have been intensified by an unusually large construction program and the effects of the energy crisis.

I. The Industry Problem

The Need for Capital

The capital requirements of the electric utility industry are vast. Since 1967 electric utilities have accounted for more than 10 percent of all new plant and equipment expenditures. Moreover, in the five years between 1967 and 1972, their share grew dramatically; so that even with recent cutbacks, electric utilities still accounted for approximately 15 percent of total capital expenditures in 1974 and the first half of 1975. (Table I)

There is, of course, considerable uncertainty as to the industry's future construction requirements. As of the end of September, kilowatt-hour

[1] *Wall Street Journal*, June 4, 1975.

[2] This figure, which is for 1973, includes the companies' shares of jointly owned nuclear plants. Source: Calculated from individual company prospectuses; National Coal Association, *Steam Electric Plant Factors, 1974*, and the Edison Electric Institute, *Statistical Yearbook*, 1973.

Table 1

NEW PLANT AND EQUIPMENT EXPENDITURES — BILLIONS OF CURRENT DOLLARS

	All Industries	Public Utilities— Electric	Electric Utilities As a Percent of All Industry
1975-I+II, annual rate	113.52	16.72	14.7
1974	112.40	17.63	15.6
1973	99.74	15.94	15.9
1972	88.44	14.48	16.3
1971	81.21	12.86	15.8
1970	79.71	10.65	13.3
1969	75.76	8.94	11.8
1968	67.76	7.66	11.3
1967	65.47	6.75	10.3
1966	63.51	5.38	8.4

Source: *Survey of Current Business,* Table S-2.

output for 1975 was less than 1.7 percent[3] above the corresponding period in 1974; and debate goes on both within and without the industry as to whether this low growth represents a permanent response to higher rates or merely a temporary aberration. In general, however, most observers agree that while a return to growth rates of 7 and 8 percent is unlikely as long as real prices remain high, the demand for electricity will pick up as the economy improves and the shock of the high prices wears off. In the long run, growth will be further strengthened by a trend away from the use of oil and gas towards relatively flexible[4] and hence, more secure electricity.

Economic Growth in the Future, a Report of the Edison Electric Institute Committee on Economic Growth, Pricing and Energy Use, has estimated that for the 25-year period, 1974 through 1990, the consumption of electric energy in kilowatt-hours will grow at an annual rate of 5.3 to 5.8 percent. Construction expenditures are forecast to rise 10 percent per year, reflecting the shift away from oil and natural gas plants to the more

[3]Edison Electric Institute, *Electric Output,* October 1, 1975.

[4]Many fossil-fueled plants can be switched at some cost from one fuel to another. Moreover, most utilities have a mix of generating sources so that relying on electricity is seen as spreading one's risks.

capital intensive coal, nuclear and pumped storage hydro capacity. Total capacity needs for the period in current dollars are estimated to be $750 billion.[5]

For the shorter time period of 1975 through 1980, Murray Weidenbaum has estimated total capital outlays at $120 billion.[6] If past trends continue, 60 to 70 percent of these funds will be raised externally.

Internal Funding

In 1964 approximately 60 percent of the electric utilities total capital funding came from internal sources; by 1972 this had fallen to just over 30 percent (Table 2(a)). Two-thirds of the decline can be attributed to the decreasing importance of depreciation. As Table 3 shows, depreciation is approximately 3.02 percent of the book value of operational electric plant and with construction expenditures growing at an annual rate of approximately 17 1/2 percent over this period, the increase in electric plant and consequently depreciation has simply not kept pace. In the mid-sixties existing plant in service was so large relative to construction expenditures that even large dollar additions to plant resulted in relatively small percentage increases, and consequently depreciable plant and therefore depreciation grew much more slowly than new construction.[7] Furthermore,

[5]*Economic Growth in the Future,* Report of EEI Committee on Economic Growth, Pricing and Energy Use, Executive Summary, June 1975. These forecasts are based on growth in real GNP of 3.7 percent.

[6]Murray Weidenbaum, "Future Capital Requirements of the Electric Utility Industry 1974-80," *Public Utilities Fortnightly,* January 30, 1975, p. 15.

[7]Construction work in progress is not depreciable. Thus, the percentage change in operating plant, or "electric plant in service" can be approximated in the following manner:

$$\text{Change in plant} = \frac{Pt - P(t\text{-}1)}{P(t\text{-}1)}$$

$$= \frac{P(t\text{-}1) + C(t\text{-}n) - dP(t\text{-}1) - P(t\text{-}1)}{P(t\text{-}1)}$$

$$= \frac{C(t\text{-}n) - dP(t\text{-}1)}{P(t\text{-}1)}$$

$$= \frac{C(t\text{-}n)}{P(t\text{-}1)} - d$$

where Pt = electric plant in service in period t

d = the depreciation rate, equal to a constant (3.02%)

Ct-n = gross increase in plant in service, equal to construction expenditures in an earlier year. (In fact, the increase would be equal to some combination of the expenditures in several years.) With construction expenditures growing at a rate of over 17 percent, new additions would have to be 20 percent of existing capacity for electric plant in service and therefore, depreciation to grow at the same rate.

Table 2

SOURCES OF FUNDS — CLASS A AND B PRIVATELY OWNED ELECTRIC UTILITIES

a) Including the Allowance for Funds Used During Construction (AFC)

	Net Income Less Dividends	Depreciation	Deferred Taxes	Investment Tax Credit	Total of Internal Funds	Common and Preferred Stock[1]	Long-Term Debt[2]	Notes	Total of External Funds	Total All Funds
1972										
Millions of Dollars	1,233	2,896	343	185	4,658	4,824	4,845	132	9,801	14,459
Percent	8.5	20.2	2.3	1.2	32.2	33.3	33.5	.9	67.7	100.0
1971										
Millions of Dollars	1,026	2,628	196	90	3,939	3,900	4,770	136	8,806	12,745
Percent	8.0	20.6	1.5	.7	30.9	30.5	37.4	1.0	69.0	100.0
1970										
Millions of Dollars	886	2,399	110	25	3,420	2,780	4,866	(104)	7,542	10,962
Percent	8.0	21.8	1.0	.2	31.1	25.3	44.3	(.9)	68.8	100.0
1969										
Millions of Dollars	884	2,203	94	67	3,249	1,246	3,552	845	5,643	8,891
Percent	9.9	24.7	1.0	.7	36.5	14.0	39.9	9.4	63.4	100.0
1968										
Millions of Dollars	797	2,034	75	81	2,987	1,048	3,161	481	4,680	7,676
Percent	10.3	26.4	.9	1.0	38.9	13.6	41.1	6.2	61.0	100.0
1967										
Millions of Dollars	842	1,894	56	78	2,869	736	2,630	427	3,794	6,662
Percent	12.6	28.4	.8	1.1	43.0	11.0	39.4	6.4	56.9	100.0
1966										
Millions of Dollars	810	1,774	49	60	2,694	512	2,226	186	2,924	5,617
Percent	14.4	31.5	.8	1.0	47.9	9.1	39.6	3.3	52.0	100.0
1965										
Millions of Dollars	716	1,675	51	60	2,503	376	914	348	1,638	4,141
Percent	17.3	40.3	1.2	1.4	60.4	9.1	22.1	8.4	39.6	100.0
1964										
Millions of Dollars	712	1,575	65	61	2,412	495	957	52	1,504	3,916
Percent	18.2	40.2	1.7	1.6	61.6	12.6	24.4	1.3	38.4	100.0

b) Excluding The Allowance for Funds Used During Construction (AFC)

	Net Income Less Dividends	Less AFC	Depreciation	Deferred Taxes	Investment Tax Credit	Total of Internal Funds	Common and Preferred Stock[1]	Long Term Debt[2]	Notes	Total of External Funds	Total
1972											
Millions of Dollars	1,233	(1,069)	2,896	343	185	4,658	4,824	4,845	132	9,801	13,390
Percent	1.2		21.6	2.5	1.3	26.8	36.0	36.1	.9	73.1	100.0
1971											
Millions of Dollars	1,026	(812)	2,628	196	90	3,127	3,900	4,770	136	8,806	11,933
Percent	1.7		22.0	1.6	.7	26.2	32.6	39.9	1.1	73.7	100.0
1970											
Millions of Dollars	886	(588)	2,399	110	25	2,031	2,780	4,866	(104)	7,542	10,374
Percent	2.8		23.1	1.0	.2	27.2	26.8	46.9	(1.0)	72.7	100.0
1969											
Millions of Dollars	884	(403)	2,203	94	67	2,846	1,246	3,552	845	5,643	8,489
Percent	5.6		25.9	1.1	.7	33.5	14.6	41.8	9.9	66.4	100.0
1968											
Millions of Dollars	797	(275)	2,034	75	81	2,712	1,048	3,161	481	4,689	7,402
Percent	7.0		27.4	1.0	1.0	36.6	14.1	42.7	6.4	63.3	100.0
1967											
Millions of Dollars	842	(186)	1,894	56	78	2,682	736	2,630	427	3,794	6,476
Percent	10.1		29.2	.8	1.1	41.4	11.3	40.6	6.5	58.5	100.0
1966											
Millions of Dollars	810	(128)	1,774	49	60	2,566	512	2,226	186	2,924	5,490
Percent	12.4		32.3	.8	1.0	46.7	9.3	40.5	3.3	53.2	100.0
1965											
Millions of Dollars	716	(94)	1,675	51	60	2,409	376	914	348	1,638	4,048
Percent	15.4		41.4	1.3	1.5	59.5	9.3	22.6	8.6	40.4	100 0
1964											
Millions of Dollars	712	(85)	1,575	65	61	2,327	495	957	52	1,504	3,831
Percent	16.4		41.1	1.7	1.6	60.7	12.9	25.0	1.3	39.2	100.0

Note: Sums may not equal totals due to rounding.

[1]Common and preferred stock equals change in proprietary capital minus net income less dividends. This differs slightly from the change in proprietary capital less the change in retained earnings, because of the conversion of retained earnings into stock.

[2]Net of retirements and refinancings.

Source: Federal Power Commission, *Statistics of Privately Owned Electric Utilities in the United States.* Calculated from summary tables.

Table 3

DEPRECIATION AND AMORTIZATION AS A PERCENT OF ELECTRIC PLANT IN SERVICE
—CLASS A AND B PRIVATELY OWNED ELECTRIC UTILITIES

	Electric Plant in Service[1] ($ mill.)	Percent Change Electric Plant in Service (Percent)	Depreciation and Amortization ($ mill.)	Depreciation and Amortization as Percent of Electric Plant in Service (Percent)
1972	$94,055	9.5	$2,896	3.07(3.04)[2]
1971	85,883	8.8	2,628	3.05(3.03)[2]
1970	78,937	8.5	2,399	3.03(3.03)[2]
1969	72,765	7.9	2,203	3.02
1968	67,408	7.7	2,034	3.01
1967	62,605	6.7	1,894	3.02
1966	58,649	5.7	1,774	3.02
1965	55,490	5.4	1,675	3.01
1964	52,638		1,575	2.99

[1]Average of current and previous year. Does not include nuclear fuel.

[2]Includes nuclear fuel.

Source: Federal Power Commission, *Statistics of Privately Owned Electric Utilities in the United States.*

since construction work in progress is not depreciable, construction expenditures are converted to operating plant only with a lag of several years, and consequently fall short of current expenditures because of inflation and the growth in demand.

However, over the next few years the decline in the contribution of depreciation should be arrested. Projections of future capacity needs are being revised downward and inflation appears to be abating. While these factors are being offset by the shift to more capital intensive technologies and environmental requirements, the growth in construction expenditures should still be less than in the past. As mentioned previously, EEI projects an average rate of increase of 10 percent. At the same time the additions to operating plant are now a substantial percentage of total plant (12 percent in 1972)[8] and are likely to increase as construction work in progress continues to come on line at the very high growth rates of the recent past.

The share of new capital funding represented by retained earnings also fell dramatically--from 18 percent in 1964 to 8.5 percent in 1972. While construction expenditures have grown at a very rapid rate, common equity increased only 8 percent per year, in part reflecting increased reliance on debt and preferred stock. At the same time the rate of return on equity has declined slightly; so that the growth in earnings has fallen far behind the increase in funding needs.

The most commonly cited explanation for the decrease in the rate of return in the late sixties is the very high rate of inflation coupled with the use of historic cost figures for rate-setting purposes. The rates which a utility is allowed to charge are usually designed to yield a desired rate of return given historic costs, plus known future increases. Estimates of increased cost based on projections of inflation are only now receiving acceptance. In the early sixties these procedures worked to the utilities' advantage, for the low rates of inflation were more than offset by growing demand and increased exploitation of economies of scale. However, as inflation accelerated and the opportunities for production efficiencies were exhausted, this was no longer true and an increasing number of utilities have been unable to realize their allowed rates of return. The problem was exacerbated in 1974 with the fall-off in demand brought about by conservation efforts and the recession.

This decline in the role of retained earnings has been made even more significant by the rapid growth in the costs of financing construction. In 1964 the cost of borrowed and equity funds used for construction purposes was only 2 percent of total construction costs. By 1972, reflecting rising interest rates and longer construction lead times they were over 7 percent and absorbed 87 percent of retained earnings (Table 2(b)). With these costs taking up a growing share of internal funds, the utilities must resort to more external financing in order to construct a plant of given capacity and cost exclusive of borrowing charges.

[8] FPC, *Statistics of Privately Owned Electric Utilities in the United States*: net addition to electric plant in service plus depreciation.

Also, although these costs must be met out of current income during the construction period, there are no offsetting revenues, for construction work in progress is not included in the rate base. Instead, the cost of financing construction is considered part of the total costs of the project and is added to the rate base when the facility is completed. Also an addition is made to nonoperating income so that nominal earnings are not depressed during construction by the appearance in the income statement of what are really capital expenditures. However, this addition, known as allowance for funds used during construction (AFC), is merely a bookkeeping entry and does not represent cash revenues.

This treatment of construction work in progress and the cost of financing construction affects earnings in several ways. First, as Appendix A demonstrates, the addition of AFC to the rate base after the plant is completed does not completely offset the failure to include work in progress during the construction period, and thus creates a discrepancy between allowed and realized rates of return. Also, as long as the utility continues to build, there will be a gap between nominal and actual cash earnings. Since most utilities' construction programs do not end with the completion of a single plant, it is possible that actual earnings will never catch up with nominal earnings.

Secondly, the use of AFC can mean considerable volatility in reported earnings. When a project goes into commercial operation AFC is automatically eliminated; however, to include the newly completed plant in the rate base requires a hearing. Given regulatory lags this may mean a period of some months during which earnings are abnormally low because there is no AFC and also no increase in rates to reflect the addition of the new plant.

Lastly, severe cash flow difficulties may develop. Most purchasers of utility stock are looking for income rather than appreciation; so that utilities pay out approximately 70 percent of their common earnings in dividends. The addition of AFC may give the appearance that earnings are sufficient to support dividend payments while cash flow is inadequate. For example, Savannah Electric and Consolidated Edison both failed to meet dividend payments primarily because they did not have the cash revenues. Earnings *appeared* to cover historic dividend rates, but an important element of these earnings was the noncash AFC. Other companies face this same problem to a lesser degree, and are able to maintain dividends only by borrowing.

External Financing

a) *Common Stock*. As the utilities have become more dependent on external funding sources, the market has grown unreceptive to new issues. In 1974 almost all the utilities' common stock sold below book value. For the 71 major utilities that do not have substantial nonelectricity revenues, the median ratio of price to book value was .77. For only ten utilities was the ratio above one.[9]

Utilities are understandably loathe to issue stock at such a time, for to do so dilutes the value of the existing shareholder's investment and consequently his potential earnings. Moreover, repeated dilutions will be perceived by the market, which will then further discount the price of the stock.

In 1974 skyrocketing fuel costs, plus cutbacks in demand, caused many utilities' earnings to fall.[10] In addition, Consolidated Edison's failure to pay its second quarter dividend threw into question the value of utility stocks as a stable source of income, and at the same time interest rates on all forms of debt reached record levels, offering the investor seeking income many attractive alternatives to utility stocks. However, despite these unique features it would be a mistake to view the financing difficulties of the utilities as a problem of recent origin.

Chart I compares the ratio of market price to book value[11] for Moody's utility composite with that for industrials. Since 1965 there has been a steady downward trend for utilities in contrast with an erratic but only slight decline for industrials.

As Table 4 shows, econometric analysis indicates that this marked deterioration in the ratio of price to book value is largely explained by the decline in the return to equity relative to the yield on alternative investments, represented here by Aaa industrial bonds. Coverage ratios have also had a significant influence, probably because the market views them as a measure of the riskiness of the investment. Chart II compares the actual values for the ratio of price to book value (p/B-1) with the fitted values produced by equation (2). The closeness of the fit suggests that much of the fall in stock prices in 1974 was the culmination of a downward trend in utility prices brought about by the decline in relative earnings and decreasing coverage ratios. Certainly, there were unusual and hopefully nonrecurring problems in 1974; but these precipitated a financial crisis which may well have come in any case.

b) *Long-Term Debt and Preferred Stock.* While the prospect of issuing common stock in 1974 was generally unattractive, alternatives were

[9] These are all the utilities analyzed by *Valueline* except those which derived more than 30 percent of revenues from nonelectricity sources, according to the FPC *Statistics of Privately Owned Electric Utilities.* An important exception to this exclusion is the New England Gas and Electric Association which receives substantial revenues from gas operations, but is still included. The eight largest New England companies are in the sample and all the regions are well represented except the East-South Central states which are supplied largely by the publicly owned Tennessee Valley Authority.

[10] Forty-two of the 71 utilities experienced declines in reported earnings per share in 1974. Source: *Valueline.*

[11] The ratio for year t is the market price for year t divided by the book value per share as of December 31 of (t-1).

Table 4

REGRESSION TO EXPLAIN THE DECLINE IN MARKET PRICE RELATIVE TO BOOK VALUE

1. $$\frac{p}{B-1} = \underset{(49.26)}{0.891}\,\frac{E-1}{R} - \underset{(-1.93)}{0.921}\,\frac{N}{C-1}$$

$\bar{R}^2 = 0.955$

INTERVAL: 1962-1973; annual data

2. $$\text{Log}\,\frac{p}{B-1} = \underset{(-3.07)}{-1.024} + \underset{(3.21)}{0.678}\,\log\frac{E-1}{R} + \underset{(2.37)}{0.939}\,\log \text{COV-1}$$

$\bar{R}^2 = 0.942$; normalized $\bar{R}^2 = 0.956$

INTERVAL: 1962-1973, annual data

where:

- p is the average market price of Moody's 24 utilities.
- B is the average book value of the 24 utilities.
- E is the rate of return to common equity for investor-owned utilities.
- N is the volume of new stock issues for investor-owned utilities.
- C is the value of common equity for investor-owned utilities.
- COV is the coverage ratio, or earnings before interest and income taxes divided by interest, for investor-owned utilities.
- R is the yield on Aaa industrial bonds.

A more complete description of these equations appears in Appendix B.

Chart I

RATIOS OF MARKET PRICE TO PER SHARE BOOK VALUE
MOODY'S INDUSTRIAL AND UTILITY AVERAGES

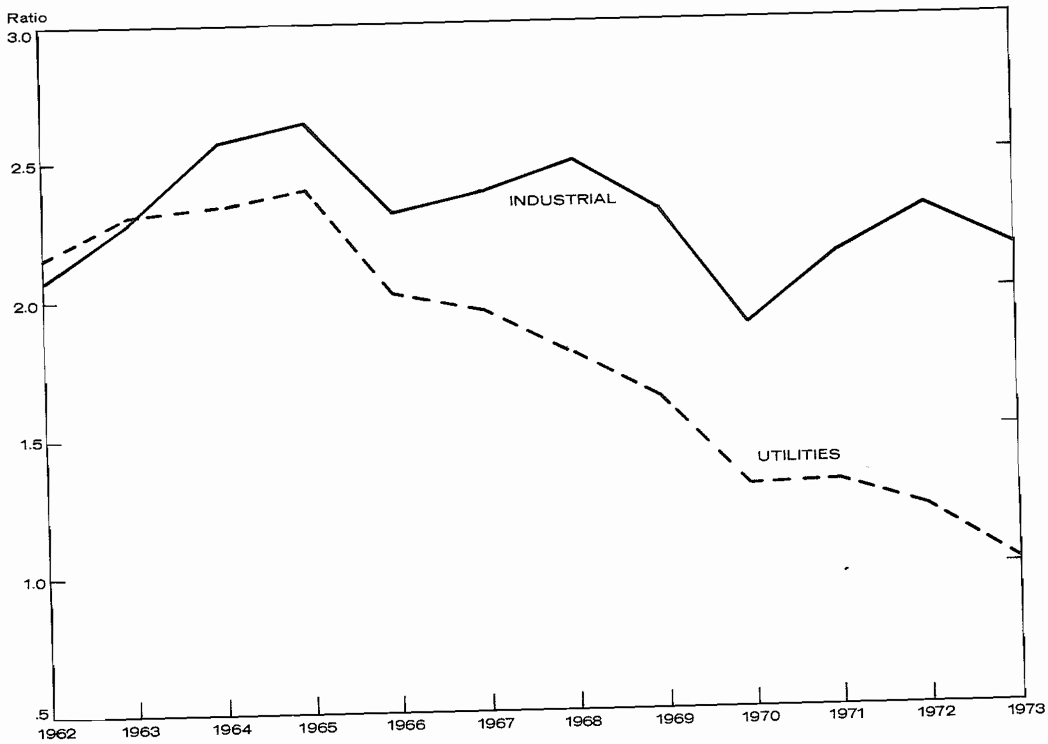
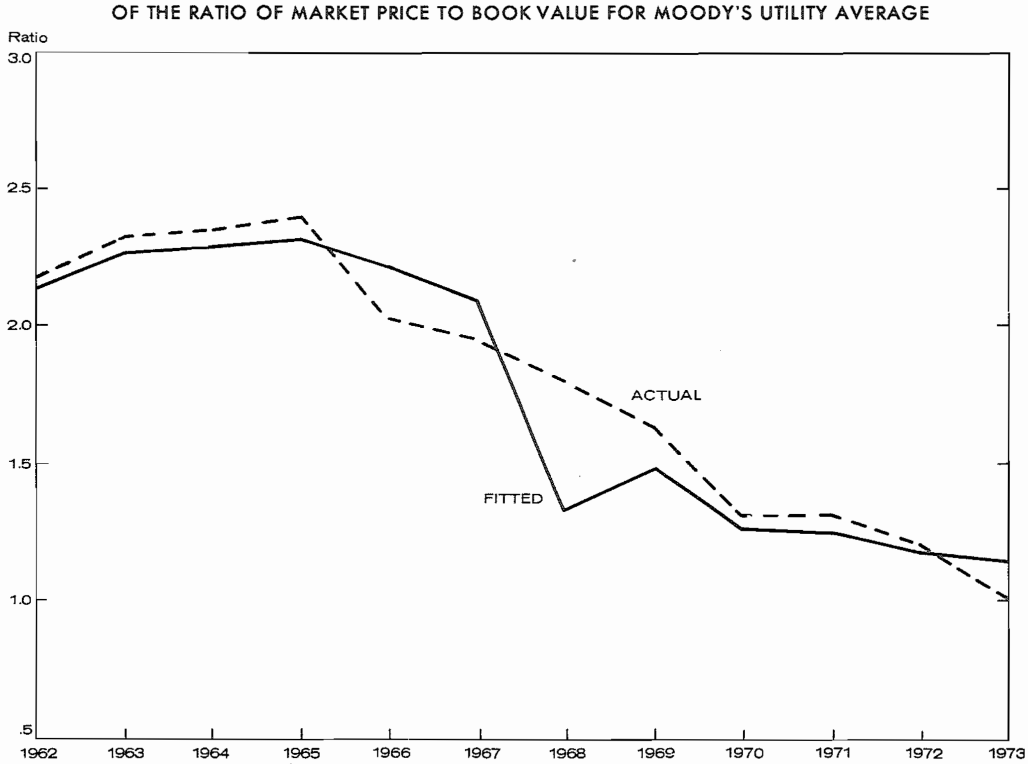


Chart II

COMPARISON OF ACTUAL AND FITTED VALUES
OF THE RATIO OF MARKET PRICE TO BOOK VALUE FOR MOODY'S UTILITY AVERAGE



limited. Many utilities found that, as a result of declining earnings and rising interest costs, the coverage requirements of bond indentures and preferred stock provisions had become binding constraints.

Bond indentures typically preclude the issuance of new senior debt if net earnings available for interest fall below twice the annual bond interest, including that on the bonds to be issued; similarly, additional preferred stock may not be issued if available earnings are less than 1 1/2 times annual interest charges and preferred stock dividends.

A good measure of the strength of these restrictions is the coverage ratio, or the ratio of earnings before interest and income taxes to interest charges. In 1967 the average coverage ratio for the 71 major utilities was 5.02; by 1973, 2.96. For nine utilities it was below 2.2; and for three, less than 2.[12] While comparable data for 1974 were not available at the time of writing, it is evident that there has been further deterioration: in 1973 the ratio of operating income to interest was 2.59 for the 71 firms; in 1974, 2.2.[13]

Many utilities have been further constrained by a high degree of leverage. In 1974 the ratio of common equity to total capitalization was below 32 percent for 15 of the 71 utilities, less than 30 percent for five firms.[14] These low ratios reflect the fact that equity is the most costly source of funds. However, the market views suspiciously utilities with less than 30 percent of their total capital in common equity. In addition, bond indentures and preferred stock provisions usually restrict common dividends if the share of common equity falls below 25 percent and limit the issuance of new bonds to no more than 60 percent of additional property. Consequently, firms with low equity ratios must balance large sales of bonds or preferred stock with issues of common stock. However, as we have seen, 1974 was a most inopportune time for such offerings.

Also, the record yields on fixed income securities in 1974 were themselves a strong deterrent to new issues of bonds and preferred stock, particularly since many utilities viewed these as temporary and were unwilling to be locked into such high cost debt for a long period. In 1974 the average yield on Moody's new Aa utility bonds was 9.41 percent, compared to 7.83 percent in 1973 and the previous high of 8.74 in 1970.[15]

These problems have been exacerbated by the declining fortunes of the primary purchasers of preferred stock — the corporate investor, particularly the insurance companies. Because of regulatory lags and the failure to take adequate account of the effects of inflation on claims, the multi-line companies are experiencing sharp declines in operating earnings. To

[12]Calculated from *Moody's Public Utility Manual*, 1974.

[13]Source: *Valueline*, Spring 1975.

[14]*Valueline.*

[15]Data Resources Inc., *The Data Resources Review.* Also in 1974 the yield on preferred stock like that on long-term debt reached a record level. For the year it averaged 9.17 percent, and for several months exceeded 10 percent. Salomon Brothers, *An Analytical Record of Yields and Yield Spreads*, January, 1975.

offset this the industry is seeking to bolster investment income. This has increased the demand for corporate bonds, notes and debentures — although apparently not those of the utilities — and has greatly slowed the rate of acquisition of preferred stock.

II. The New England Experience

Recent Difficulties — Restrictions on Debt and Preferred Stock

In general, the experience of the eight largest New England utilities during the recent crisis has paralled that of the industry. The problems are similar to those faced elsewhere, but somewhat more severe. Since July 1973, four of these New England companies have had their bond ratings lowered by Moody's and one small firm's rating was temporarily withdrawn (Table 5). In addition, 4 of the 18 electric utilities removed from the lists of legal investments for savings banks in Connecticut, Massachusetts, New Hampshire, and New York were New England companies.[16]

These changes are, of course, costly. By the end of 1974 the spread between Moody's Aaa and Baa utility bonds was 208 basis points; and one New England subsidiary company derated to Baa in December 1974 paid 13 1/8 percent on bonds sold the following month! Since then the gap has narrowed; but as of the end of September it was still 170 points.[17]

High interest rates, together with a massive construction program and declining earnings, have seriously eroded the coverage ratios of the New England utilities. In 1967 the average ratio of earnings before taxes and interest charges to interest for the eight largest New England firms was 4.58. By 1973 it had fallen 50.2 percent to 2.28 (Table 6). The utilities' own calculations show further deterioration in 1974, with the result that several firms were unable to issue additional long-term debt or preferred stock. Construction programs were maintained with bank loans and commercial paper, usually at rates in excess of 11 percent. Others retained the option of issuing senior securities, at least temporarily, only because they were permitted to change accounting practices so as to defer the recording of fuel expenses and accrue unbilled revenues. These changes did not increase cash flow but raised reported earnings and consequently legal coverage ratios.

Largely because of such difficulties, short-term borrowing reached unusual proportions in 1974, ranging from 10.8 percent of total capitalization to 83 percent. In 1970 the range was from .4 to 22.8 percent with only three firms in excess of 10 percent.[18]

[16]Removals were taken from *Moody's Public Utility News Reports* from July 1974-May 1975. For Connecticut, removals were recorded for the period 6/30/74-3/31/75; for Massachusetts, 4/1/74-3/1/75; for New Hampshire, 5/31/74-3/31/75 and for New York, 7/1/73-7/1/74. These are the only states with such lists.

[17]*Moody's Public Utility News Reports*, January 7, 1975 and October 7, 1975.

[18]Total capitalization is usually defined as long-term debt and equity. It does not include short-term debt. Calculations were made from company prospectuses.

Table 5

MOODY'S PUBLIC UTILITY NEWS REPORTS
BOND RATINGS
REVISIONS SINCE JULY 13, 1973

Downward Revisions	From	To
1973.4	Aa	A
Duke Power Mortgages	A	Baa
Debentures	Aa	A
*Boston Edison		
1974.1	A	Baa
Consolidated Edison	Aa	A
— Edison Electric Illum.	Aa	A
— Kings County Elec. Light and Power	A	Baa
— Staten Island Edison	A	Baa
— Yonkers Electric Light and Power	A	Baa
— Westchester Lighting	A	Baa
*Public Service Co. of New Hampshire		
1974.2		
*Northeast Utilities	Aa	A
*— Western Massachusetts	Aaa	Aa
Baltimore Gas and Electric Mgt.	Aa	A
Deb.	Aa	A
Detroit Edison	Aa	A
Columbus and Southern Ohio Electric	Aa	A
Iowa Electric Light and Power	suspended	
*Central Vermont Public Service	suspended	
Consolidated Edison	suspended	
— Edison Electric Illum.	suspended	
— Kings County Elec. Light and Power	suspended	
— Staten Island Edison	suspended	
— Yonkers Electric Light and Power	A	Baa
Savannah Electric and Power Mgt.	Baa	Ba
Deb.		
American Electric Power Co.	A	Baa
— Ohio Power Co. Mgt.	Baa	Ba
Deb.	A	Aa
Citizens Utilities	Baa	Ba
*Eastern Utilities Assoc.	A	Baa
*— Blackstone Valley Gas and Electric	A	Baa
*— Brockton Edison	A	Baa
*— Fall River Electric and Light	Aa	A
Delmarva Power and Light	A	Baa
*Boston Edison	Aa	A
Virginia Electric and Power Mgt.	A	Baa
Deb.		
1974.3		
*Northeast Utilities	Aa	A
*— Hartford Electric Light	Aa	A
*— Connecticut Light and Power	Aaa	Aa
Ohio Edison	Aa	A
— Pennsylvania Power Co.	Aa	A
Florida Power Corporation Mgt.	A	Baa
Deb.	A	Baa
Detroit Edison		
1974.4	Aa	A
Philadelphia Electric Mgt.	A	Baa
Deb.	Aa	A
Dayton Power and Light	Aaa	Aa
Cincinnati Gas and Electric	Aa	A
Florida Power and Light	Aa	A
San Diego Gas and Electric Mgt.	A	Baa
Deb.		
*Northeast Utilities	A	Baa
*— Western Massachusetts		
Southern Company	A	Baa
— Georgia Power	A	Baa
Consumers Power Mgt.	Baa	Ba
Deb.		
1975.1		
Savannah Electric and Power	suspended	
Southern Company	suspended	
— Georgia Power		
American Electric Power	A	Baa
— Appalachian Power Mgt.	Baa	Ba
Deb.	A	Baa
Arizona Public Service	Aaa	Aa
Houston Lighting and Power Mgt.	Aa	A
Deb.		
American Electric Power	A	Baa
— Indiana and Michigan Elec. Mgt.	Baa	Ba
Deb.	Aa	A
Union Electric	A	Baa
Carolina Power and Light	A	Baa
Iowa Electric Lighting and Power	Aaa	Aa
Cleveland Electric Illum.		
American Electric Power	A	Baa
— American Gas and Electric	A	Baa
Pacific Power and Light	A	Baa
San Diego Gas and Electric Mgt.	Baa	Ba
Deb.		
Upward Revisions		
1973.4		
*Cape and Vineyard Electric	A	Aa
1974.1		
Public Service of New Mexico	A	Aa
1974.4		
*Central Vermont Public Service	reinstated	Baa
1975.2		
Consolidated Edison	reinstated	Baa
— Edison Electric Illum.	reinstated	Baa
— Kings County Electric Lighting and Power	reinstated	Baa
— Staten Island Edison	reinstated	Baa
— Westchester Lighting	reinstated	Baa
— Yonkers Electric Lighting and Power	reinstated	Baa

*Asterisks denote New England companies.

Table 6

AVERAGE COVERAGE RATIOS 1967-1973

	New England	United States	New England as a Percent of U.S.
1967	4.58	5.02	91
1968	4.01	4.56	88
1969	3.35	4.07	82
1970	2.75	3.37	82
1971	2.61	3.17	82
1972	2.92	3.22	91
1973	2.28	2.99	76

Note: The New England figure is the unweighted average for the eight largest companies; the U.S. figure is the average for the sample of 71, including the eight New England firms.

Source: Calculated from earnings statements in *Moody's Public Utility Manual.*

However, although the existence of such extensive short-term debt is usually a symptom of financial difficulties, it cannot be taken as proof. Most of the New England firms finance on-going construction on a short-term basis. These notes are then converted to stocks and bonds according to market conditions and company needs. Consequently, New England's construction program, which averaged $640 million per year from 1970 through 1974,[19] would by itself have resulted in a substantial increase in the average balance of short-term liabilities.

Moreover, as discussed earlier, the record interest levels of 1974 may have prompted firms to borrow short in order to avoid being locked into very high cost long-term debt, and at least one firm chose to issue notes in order to defer a long-term offering until a new facility came on line. It was the firm's belief that the market would respond favorably to the new plant's operation by allowing a lower interest rate on a pending mortgage issue.

Nonetheless, a number of large companies had no alternative to short-term borrowings if they were to maintain their construction programs, and in hearings before the FPC and state regulatory agencies the need for higher rates to generate revenues sufficient to maintain coverage ratios has been a central argument.

Primarily because of rate increases, in some cases subject to refund, and the elimination of lags in the fuel adjustment formulas, coverage difficulties for most firms have been temporarily alleviated. At the time of writing one large utility was unable to meet its preferred stock provisions and the subsidiary of another was still limited entirely to short-term financing, but most companies either had issued or expected to issue senior debt in 1975.

This cannot, however, be taken as a sign of any permanent improvement. The ratios of earnings to fixed charges are likely to be little better in 1975 than they were in 1974 and unless rate increases keep pace with rising costs, the difficulties of the past year will certainly be repeated.[20]

Several of the New England firms have been further restricted by the low share of common equity in total capitalization. In both 1973 and 1974 the average common equity ratio for the eight largest New England companies was 33 percent.[21] With 30 percent considered a floor, this means that major issues of either long-term debt or preferred stock should be

[19]Calculated from the prospectuses of the eight firms.

[20]Indeed, coverage restrictions have become almost a chronic problem for the New England companies. Several subsidiary companies could not meet earnings requirements for new bonds as early as 1970, while another was precluded from issuing both bonds and preferred stock in late 1971 and early 1972.

[21]In addition, the subsidiaries of one of the firms with a higher equity ratio (35.6 percent in 1974) have unusually restrictive bond indentures: long-term debt may not exceed 50 percent of total capitalization. Thus, although leverage is not very great, bond issues must still be accompanied by increased equity.

balanced by a sale of common shares. However, all of the companies' stock sold well below book value in 1974 and continued to do so throughout the first half of 1975.

Restrictions on Issues of Common Equity

In 1974 the average ratio of market price to book value for the eight largest New England utilities was .69, substantially lower than a national average for the 71 companies of .83.[22] Six of the eight firms were in the lowest 25 percent of the distribution.[23] This situation has subsequently improved; but as of September 30, 1975, the average ratio of price to book value was still only 0.76 for the eight New England companies.[24]

As was done for the industry as a whole, it can be shown statistically that the ratios of price to book value for individual utilities are largely determined by the return to equity relative to the yield on alternative investments (Table 7). Coverage ratios, the percentage change in common shares, and the dividend payout ratio are also significant, although lesser factors. The importance of the payout ratio is particularly interesting for it supports the contention that the buyers of utility stock are interested in income rather than appreciation, and it justifies the utilities' efforts to maintain dividends despite declining earnings.

The poor performance of New England utility stocks is therefore primarily attributable to low earnings which have depressed both rates of return and coverage ratios. For several firms this effect has been intensified by issues of common stock. However, as Appendix C describes in more detail, it also appears that the market discounts the New England companies' stock somewhat more than the financial variables warrant. This discount appears in part related to perceptions of regulatory climate, for a premium is placed on the stock of utilities in Texas and Oklahoma where regulation is minimal.

Pressures on Earnings

a) *Construction.* While New England utilities have shared in the general industry problems of inflation, regulatory lags, and rising interest costs, a big factor underlying both the region's relatively low earnings and its need for capital has been its construction program. Even by industry

[22]This is the average ratio of the 1974 market price to book value per share as of December 31, 1973. Calculated from *Valueline.*

[23]The ratio of price to book value for the New England firms has in fact been below the national average since the mid-sixties. In 1965 the average for New England was only 70 percent of the average for the 71 firms. Since that time there has been a convergence, with New England reaching 87 percent of the national average in 1973. However, 1974 marked a reversal of this trend with the New England figure dropping to only 83 percent; moreover, the significance of this gap is undoubtedly much greater than in the past, since in 1974 both ratios were below one.

[24]*Wall Street Journal*, October 1, 1975. Market prices were divided by book values as of December 31, 1974.

Table 7

REGRESSION TO EXPLAIN THE DECLINE IN MARKET PRICE RELATIVE TO BOOK VALUE

These regressions use time series data pooled over the 71 utilities. *ci* designates multiple constants. The individual values are listed in Appendix C.

INTERVAL — 1965-1974

$$1.\quad \frac{P}{B-1} = ci + \underset{(55.77)}{1.039}\,\frac{E}{R}$$

$\bar{R}^2 = .81$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.196}{1.368} = .14$ U.S. $\frac{.194}{1.731} = .11$

INTERVAL — 1968-1974

$$2.\quad \frac{P}{B-1} = ci + \underset{(24.34)}{1.205}\,\frac{E}{R} + \underset{(5.19)}{.062}\ \text{COV-1} \underset{(-4.75)}{-0.811}\ \text{NS} + \underset{(10.21)}{1.124}\ \text{PO}$$

$\bar{R}^2 = 0.74$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.106}{1.218} = .087$ U.S. $\frac{.144}{1.454} = .099$

$$3.\quad \frac{P}{B-1} = ci + \underset{(25.35)}{1.834}\,\frac{D}{R} + \underset{(4.80)}{.057}\ \text{COV-1} \underset{(3.33)}{-0.567}\ \text{NS}$$

$\bar{R}^2 = 0.75$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.089}{1.218} = .073$ U.S. $\frac{.136}{1.454} = .094$

Variables:

p — market price of common shares.
B — book value per share as of December 31.
E — the rate of return to equity as reported.
D — ratio of dividends to equity as reported.
R — yield on Moody's Aaa industrial bonds.
PO — payout ratio
COV — coverage ratio
NS — percentage change in common shares (has not been multiplied by 100%).

All variables except R and COV have been calculated from data contained in *Valueline*. COV has been calculated using *Moody's Public Utility Manual*.

-1 designates a lag of 1 year.

standards this has been substantial, reflecting both a major modernization effort and a high proportion of more costly nuclear capacity.[25] From 1968 through 1974 investor-owned utilities in New England accounted for 5.67 percent of capital expenditures by all investor-owned utilities in the contiguous United States. (Table 8).[26] Capacity on the other hand, was only 4.8 percent of the national total in 1973; generation, 4.95 percent.[27]

To finance this construction program the New England utilities have borrowed heavily. Between 1970 and 1974 the long-term debt of the eight largest firms rose 40 percent, from $2.2 billion to $3.1 billion, and notes payable almost tripled from $.36 billion to $.97 billion. At the same time approximately $180 million in bonds bearing interest rates of 2, 3, and 4 percent matured, having to be refinanced at rates of 8 percent or more.[28]

This tremendous expansion in debt at high rates has sent interest costs soaring. From $126 million in 1970 they more than doubled to $283 million in 1974. During the same period income before interest charges, including the allowance for funds used during construction, increased 88 percent; so that the share of gross income absorbed by interest rose from 44.5 percent to 52.9 percent.[29] Coverage ratios plummetted. For individual utilities these changes were even more striking. For one company the proportion of gross income going to interest rose from 50.9 percent to 74.8 percent, exhausting the entire dollar increase in gross income and sharply lowering the rate of return to equity.

Such an extensive construction program also means that a large proportion of capital is tied up in work in progress, which is not included in the rate base and generates no return. For the eight companies, work in progress in 1974 accounted for over 16 percent of total property, plant and equipment, and ranged from a low of 5.2 percent to a high of 32.9 percent.[30]

[25]In 1968, 33 percent of the steam capacity of New England's A and B privately owned utilities was in units of 500 or more megawatts (MW); 30 percent in units of 300 MW or less. Some 8 percent of steam capacity came from nuclear plants. By 1973, 59 percent of steam capacity was in units of greater than 500 MW and 22 percent in units of 300 MW or less. Twenty-five percent of steam capacity was nuclear power. Source: New England Regional Commission, *A Study of the Electric Power Situation in New England, 1970-1990,* and calculated from National Coal Association, *Steam-Electric Plant Factors, 1974.*

[26]*Electrical World, Annual Statistical Report,* March 1969, 1970, 1971, 1972, 1973, and 1974.

[27]Edison Electric Institute, *Statistical Year Book for 1973.*

[28]*Moody's Public Utility Manual,* 1969.

[29]These are weighted averages, the weights being each utility's income before interest. The simple averages for 1970 and 1974 are 44.7 and 55.3, respectively. Figures are calculated from annual reports in *Moody's Public Utility Manual* and prospectuses.

[30]The weighted average of work in progress to property, plant and equipment was 16.5 percent; the unweighted average, 16.1 percent. The figures do not include investments in joint nuclear projects, which are carried at equity value. If these were included, the figures would be 16.1 percent and 15.8 percent respectively, and the range from 4.8 to 32.5 percent. All figures are as of December 31, 1974 except for the Public Service Company of New Hampshire which is for July 31, 1974.

Table 8

CAPITAL EXPENDITURES OF INVESTOR-OWNED UTILITIES

UNITED STATES AND NEW ENGLAND

	United States ($ mill.)	New England ($ mill.)	New England/ United States (Percent)
1968	$ 7,139.8	$ 400.6	5.6
1969	8,289.0	495.0	6.0
1970	10,144.8	688.1	6.8
1971	11,893.7	681.5	5.7
1972	13,385.4	772.4	5.8
1973	14,907.4	838.2	5.6
1974	17,087.7	825.9	4.8
Total	$82,847.8	$4,701.7	5.7

Source: *Electrical World*

As demonstrated in Appendix A, the exclusion of work in progress from the rate base causes a permanent reduction in the actual return to equity. It also means that a significant share of the New England companies' earnings is accounted for by the allowance for funds used during construction, which of course is not cash income.

Since utilities typically have high dividend payout ratios and feel compelled to maintain dividends even when earnings fall, the combination of the allowance for funds used during construction and depressed earnings may mean that firms are unable to generate sufficient cash income to cover their dividends. Indeed, after deducting the allowance for funds used in construction and non-cash accounting changes, five of the eight New England companies had earnings in 1974 which fell short of dividend payments. In one case the funds available were only 23 percent of the dividends actually declared! Yet for none of these utilities did dividends exceed nominal earnings.

Regardless of the specific source of funds, this means that the utilities were in effect, borrowing to maintain their dividends. Given the apparent importance attached to dividends by the market, this may well be the appropriate decision. However, the added interest costs mean either higher rates for the consumer or a further squeeze on earnings.

b) *The Energy Crisis.* In mid-1973 the price of residual oil was $4.50-$5.00 per barrel; in 1974 over $13.00. While national prices increased in a similar fashion the impact on costs was much greater in New England because of the region's heavy dependence on oil. In 1973 approximately 68 percent of the generation by investor-owned utilities in New England was from oil-fired plants compared to 18 percent for the Nation, and 38 percent in the Mid-Atlantic states, the next most dependent region.[31] Individual New England utilities ranged from a 30 percent dependence on oil to as high as 91 percent.[32]

To a large degree the earnings of the New England companies have been protected from the direct effects of the increase in oil prices. At the time of the crisis all the major companies had automatic fuel adjustment clauses permitting them to pass fuel costs on to the consumer. Protection was not complete, for the clauses operated with lags of one or two months; and with the rapid rise in prices, revenue shortfalls and cash flow difficulties developed. However, most of the impact of these lags on reported earnings, although not cash flow, has been eliminated. In 1974 almost all firms were permitted to change accounting practices so as to defer the recording of fuel expenses until the month in which they are billed

[31]The percent of fossil fuel was taken from the Edison Electric Institute's *Statistical Yearbook, 1973* and the proportion of fossil fuel accounted for by oil from National Coal Association, *Steam-Electric Plant Factors 1974.* The latter weights are actually for all generations, not merely investor owned; however, the differences appear insignificant.

[32]*Valueline,* Spring 1975.

to the consumer. Several of the subsidiaries of one company actually are allowed to bill fuel costs currently, thereby avoiding the cash flow difficulties of any future price increase as well as maintaining earnings.

The energy crisis also affected the utilities indirectly, for the high electric bills and the crisis atmosphere led to substantial conservation efforts and reductions in energy consumption. These cutbacks were then augmented by the recession which has severely curtailed industrial usage. Since the electric rates charged are based on projections of demand, these unusually low consumption levels have caused revenues to fall below expectations, further depressing earnings and realized rates of return.

In this regard the New England experience has been somewhat worse than the rest of the country. Nationally there was no growth in energy consumption in 1974, while in New England electric output fell 2.3 percent.[33] Moreover, the impact of these cutbacks has varied considerably among the individual utilities. One New England firm actually registered a slight increase in sales, while another experienced a decline of 9 percent.

Future Prospects

Despite the generally gloomy picture described thus far, the prospects for the New England utilities are not entirely bleak. Moreover, there is a great deal of variation among the individual companies.

As mentioned above, changes in accounting practices now protect reported earnings from future increases in the cost of fuel, although a substantial rise in prices could still cause cash flow difficulties. The New England firms are further shielded from cost increases by rate agreements which permit the pass-through of the costs of purchased power. This is significant because a substantial portion of total generation in New England is supplied under wholesaling arrangements which are not subject to normal regulatory proceedings. In 1973 approximately 17 percent of total generation was supplied by jointly owned companies selling only to their owner utilities. At the time these companies, which are really only plants, began operations, the terms of sale were approved by the relevant regulatory agencies. These contracts call for each owner to pay a share of all costs inclusive of a pre-determined return to capital so that increases in costs are automatically passed on to the buyer, and through the purchased power clause to the consumer. Also, most of the power for two utilities is supplied by wholesale subsidiaries, the rates for which are set by the Federal Power Commission. Since the Federal Power Commission must make a decision within five months or allow the requested rates to go into effect subject to refund, and since four of the six state agencies take considerably longer for their deliberations, this arrangement means that a sizable share of costs can be recovered from customers in a relatively timely

[33]This decline followed increases of 8.5 percent and 5.3 percent in the preceding two years. Source: Edison Electric Institute, *Electric Output,* January 1974 and January 2, 1975.

fashion. In this regard New England is probably better protected than other regions, although the significance of these arrangements varies considerably among the individual firms.

The problem caused by the fall-off in demand should also abate. Although electric output in New England showed no growth in the first half of 1975, much of this is attributable to the effects of the recession on industrial usage. National figures for July show sales to industrial customers down 6.3 percent from the preceding year but commercial and residential consumption some 7 percent higher.[34] As the economy revives, industrial usage should pick up. In addition demand forecasts have been revised downward so that rates will be based on more realistic estimates of sales. NEPLAN, the planning agent of the New England utilities, has forecast annual load growth of 6.4 percent over the next ten years.[35] A year ago they were projecting growth of 7.5 percent.

Most importantly the uncertainties of the demand situation, reinforced by financing difficulties, have led the New England companies to reassess their construction programs. Eight major units scheduled between 1975 and 1985, with a total capacity of 9,406 megawatts (MW) have been deferred at least one year. Two of these units have been postponed five years, with two more units totalling 1500 MW put off indefinitely. These postponements should ease the financial strains considerably, but only compared to what they would otherwise have been. *Valueline* has estimated that the capital expenditures of the eight largest firms in 1975 will be approximately 3 percent above the 1974 level, and company prospectuses indicate that average expenditures in 1976 and 1977 will be more than 30 percent above those in 1974.[36]

Moreover, these expenditures will be spread unevenly among the eight utilities, with four firms accounting for all of the increase. The need for outside capital will be even more varied: the companies with large construction programs tend to be those generating the smallest proportion of funds internally. In part, this occurs because the completion of a plant increases depreciation and cash revenues, as well as reducing the need for additional construction.[37]

Nonetheless, as a region New England is in an improved position relative to the rest of the Nation, with more flexibility in scheduling future capacity additions. Some 1040 MW of new capacity were added in 1974

[34]Edison Electric Institute, *Electric Output,* October 11, 1975.

[35]New England Power Planning, *New England Load and Capacity Report,* March 1, 1974 and April 1, 1975.

[36]This includes the cost of financing construction. Rates of 9 percent are now being used to calculate AFC.

[37]For two Massachusetts companies the recent completion of large plants together with revised projections of future load growth means that more than 50 percent of construction expenditures over the next three or four years is expected to be financed from internal funds. As indicated in the industry section, this is very unusual and is certainly not representative of all of New England.

and another 2530 MW are expected in 1975. Together, these additions represent a 20 percent increase over 1973 capacity and as a result, NEPLAN estimates that there will be a reserve of more than 50 percent above the 1975 winter peak.[38] This is unusually high. The standards for reliability set by the Northeast Power Coordinating Council, to which all large New England utilities belong, imply reserve requirements over the next ten years of only 20 to 25 percent. Moreover, for the Nation as a whole, reserves were only 20 percent of the peak from 1966 through 1973.[39]

With so much capacity having just come on line, New England will require relatively fewer additions in the near future than the rest of the country. For the five years 1976 through 1980, *Electrical World* estimated in mid-1974 that the investor-owned companies in New England would complete projects with a total capacity of 5289 MW. This is 4.0 percent of the additions then planned for all investor-owned utilities,[40] and is substantially below the region's share of capacity[41] and recent construction levels. Moreover, the bulk of New England's new capacity was to have come on line in 1979 and 1980, while national additions were spread relatively evenly over the period.

To some extent, the reduced rate of construction in New England will be offset by the high proportion of planned nuclear capacity — 66 percent, compared to 35 percent for the Nation.[42] Work by Arthur D. Little indicates that a nuclear plant is likely to cost more than 50 percent more per kw than comparable coal-fired capacity. An oil-fired plant, on the other hand, is approximately 10 percent less costly than coal.[43] Applying these relationships to the proposed capacity mixes indicates that it will cost New England at least 14 percent more than the Nation per additional kw. Consequently, 4 percent of national capacity is equivalent to a minimum of 4.5 percent of construction expenditures. This is still well below

[38]New England Planning, *New England Load and Capacity Report 1974-1985,* April 1, 1975.

[39]Federal Power Commission, *Electric Power Statistics,* December 1973.

[40]Additions were calculated from scheduled projects contained in National Coal Association, *Steam-Electric Plant Factors,* 1974. They do not take account of recent deferrals, since they were compiled from the October 15, 1974 issue of *Electrical World.*

[41]Investor-owned utilities in New England accounted for 4.8 percent of U.S. investor-owned capacity in 1973, 4.95 percent of generation. Figures include Alaska and Hawaii. Source: EEI *Statistical Yearbook for 1973.*

[42]This refers to the investor-owned component only.

[43]Arthur D. Little, Inc./S. M. Stoller Corporation, *Economic Comparison of Base-Load Generation Alternatives for New England Electric,* March 1975. The Arthur D. Little study estimates that for capacity scheduled for 1983 and 1985 nuclear would cost approximately 53 percent more per kw than coal. If scrubbers were required the gap would be less than 25 percent. Converting these figures to constant dollars increases the gap in the no-scrubber case to 57 percent.

its recent share and if coal plants are required to add the very costly sulphur dioxide scrubbing equipment, the gap between per kw capital costs will be greatly reduced, as New England presently plans no new coal capacity.[44]

Because these figures do not take account of all recent cancellations and deferrals, New England's share of construction expenditures which actually take place may be very different. However, these estimates probably provide a better indication of New England's relative *need* for new capacity than a figure net of all cancellations; although to the extent that demand projections have been revised downward, the magnitude of the proposed expenditures is too great.[45]

Policy Implications

The current financial difficulties of the electric utility industry are attributable to inadequate earnings relative to the returns available from alternative investments, coupled with substantial on-going capital requirements. Unlike other industries, electric utilities feel that they have little flexibility in deciding whether and when to build. Thus they must continue to seek financing even when the market is unfavorable. The falloff in demand brought on by the energy crisis and the recession, while aggravating the earnings situation, has provided a much needed breathing space. However the problem remains: it is merely a question of whether it must be faced now or at a later date.

The difficulties of the New England utilities are essentially those of the rest of the industry, intensified by an unusually large construction program and problems associated with the energy crisis. Fortunately, the conclusion of a major phase of construction leaves a number of New England firms in a relatively strong position at the moment compared to their own recent experience and the rest of the industry. However, for the region capital requirements remain as great as ever.

The policy implications of this are clear. If the Nation and the region are to have an assured supply of electric energy for the future, realized rates of return for the utilities must be made competitive with those on other investments. This can be accomplished in a number of ways; the most direct being for regulatory agencies to raise allowed rates of return. However, a first step should be to enable the utilities to realize the returns they are presently allowed. Rate should be based on cost estimates that take account of inflation or at least use year-end figures rather than historic costs. Also, the period between the filing of the rate request and the decision should be reduced or if this does not permit thorough analysis, a

[44]These figures do not take account of the fact that New England's plants will be built later and therefore will incorporate more inflation. The region's share of historic construction expenditures is discussed earlier.

[45]Ideally one would like comparisons of future needs to exclude deferrals made because of finances. Unfortunately the distinction is usually unclear.

further adjustment to earnings can be made to account for inadequate revenue throughout the period of deliberation.[46]

Increasing cash flow will also affect earnings through lower interest costs as well as directly reducing the need for outside funding. One proposal favored by several New England utilities calls for the inclusion of construction work in progress in the rate base as well as the normalization of investment tax credits and liberalized depreciation in those states which do not now permit this.

Allowing the utilities to achieve reasonable rates of return is not incompatible with the need to protect the consumer. Regulatory agencies have a responsibility for ensuring an adequate supply of electricity as much as for holding down its cost. While recent cutbacks in plant construction are largely justified by revised projections of demand, particularly here in New England, further postponements could create future shortages. In this regard, agencies might explore the implications of treating most favorably the companies with the greatest external capital needs. Alfred Kahn of the Public Service Commission of New York has suggested this,[47] and it receives some support from the regressions presented in this paper. However, such a practice could become a reward for poor management and for failure to explore the possibilities of load management. Also, if it is continued over a period at several years, the market will recognize that rates of return tend to fall after construction is completed and will discount the stock appropriately.

Lastly, the regulator is not relieved of his obligation to scrutinize costs and where possible to press for greater efficiencies. In particular, he should question very closely the projections of future demand since this is now an area of great uncertainty, and the cost of excess capacity is very high. It may even be appropriate to reconsider traditional assumptions about reliability and desired capacity reserves. If anything, the need for effective regulation has increased, but a given of such regulation must be that the utilities receive adequate rates of return.

Will the utilities be able to raise capital in future? Regulatory agencies must find the rate of return at which the answer is yes.

[46]In an inflationary period the use of historic test years plus long rate procedures can mean sub-par earnings for two years or more, even if the regulatory body accedes to the request.

[47]The Honorable Alfred E. Kahn, "Between Theory and Practice: Reflections of a Neophyte Public Utility Regulator," *Public Utilities Fortnightly,* January 2, 1975.

Appendix A

Effect of Present Treatment of Work in Progress

Regulatory commissions in setting rates attempt to establish a composite rate of return on plant in service which will generate sufficient funds to allow a reasonable return on equity. However, with construction expenditures increasing rapidly the failure to include work in progress in the rate base means that equity holders will not realize their allowed return unless the overall rate is continually revised.

A plant is to be built with a cost of C excluding the cost of funds used during construction. All funds are assumed to be acquired at the beginning of the construction period (in fact funds would be added over time as needed). The plant begins operation at the end of year n.

For simplicity it is assumed that the plant effectively lasts forever with depreciation being offset by continual reinvestment.

If r is the allowed rate of return on equity, the equity investor would expect a stream of income with a present value of

$$V_1 = \frac{rweC}{x}$$

where we is the share of equity in the plant[48]
x is the discount rate.

With work in progress included in the rate base this would in fact occur. If r* is the total composite return on capital, the stream of income before interest charges and income taxes would be

$$R^* = \frac{r^*C}{x}$$

and the return to equity

$$\frac{rweC}{x} = \frac{r^*C - iwdC - t(r^*C - iwdC)}{x}$$

where r* is the total composite rate of return to capital before taxes.
i is the rate of interest on the debt component of C.
wd is the share of C accounted for by debt.
t is the income tax rate.

[48]Preferred stock has not been included in the analysis but could be added with no change in the conclusion.

Under present procedures however, there would be no stream of income from the investment until the plant became operable in the year n+1. (AFC is a noncash addition to income). At that time the cost of funds used during construction (AFC) would be included in the rate base. The value of AFC in any year before the plant is operative is:

$$r^1 C \text{ where } r^1 = rweC + iwdC$$

(r^* differs from r^1 by the inclusion of taxes).
Thus in year (n+1) the rate base would be $C + nr^1C$ and the value of the stream revenues available to pay the total cost of capital would be:

$$R^{**} = \frac{r^*(C + nr^1 C)}{x(1+x)^n}$$

With regulation the composite return r^1 should be equal to the discount rate x, the marginal cost of capital for the firm; and in fact the actual rates being used to calculate AFC are those one would choose as discount rates. For the major New England utilities the rate r^1 in 1974 was usually 8 percent, and has now been increased to 9 percent. Thus:

$$R^{**} = \frac{r^*(C + nr^1 C)}{x(1+x)^n} = \frac{r^*C(1+nx)}{x(1+x)^n}$$

In addition, the current approach increases the return to equity during the construction period by reducing taxes. Even though AFC is not considered taxable income, the interest costs of funds used for construction are still considered an expense for tax purposes.

The value of this reduction in taxes is

$$\sum_{y=1}^{n} \frac{tiwdC}{(1+x)^y} = \frac{tiwdC}{x} - \frac{tiwdC}{x(1+x)^n}$$

The value of the return to equity under this approach is

$$V_2 = \underset{(1)}{\frac{r^*(C+nxC)}{x(1+x)^n}} - \underset{(2)}{\frac{iwdC}{x}} - \underset{(3)}{\frac{t(r^*(C+nxC) - iwdC)}{x(1+x)^n}} + \underset{(4)}{\frac{tiwdC}{x}} - \underset{(5)}{\frac{tiwdC}{x(1+x)^n}}$$

where term (1) is the total stream of revenues available to pay interest charges, taxes and the return to equity.
(2) is the interest costs of the project, which are incurred from the beginning even though revenues do not appear until n+1.
(3) is the taxes paid on revenues from the project.
(4)(5) represent the tax savings from expensing interest costs during the period of construction.

Thus

$$V_1 - V_2 = \frac{r^*C}{x} - \frac{iwdC}{x} - \frac{t(r^*C - iwdC)}{x}$$

$$- \left[\frac{r^*C(1+nx)}{x(1+x)^n} - \frac{iwdC}{x} - \frac{t(r^*C\,(1+nx) - iwdC)}{x(1+x)^n} + \frac{tiwdC}{x} - \frac{tiwdC}{x(1+x)^n}\right]$$

$$= \frac{r^*C(1-t)}{x} - \frac{r^*C(1-t)(1+nx)}{x(1+x)^n}$$

$$> 1, \text{ since } \frac{(1+nx)}{(1+x)^n} < 1$$

as long as $n > 1$

Thus the value of the return to equity is less with the current treatment of AFC than if work in progress were in the rate base.

Appendix B

The market price of a stock should be closely related to the stream of expected earnings per share discounted by the opportunity cost of capital. Thus:

$$p_o \approx \frac{e_1}{(1+r_o)} + \frac{e_2}{(1+r_o)^2} + \frac{e_3}{(1+r_o)^3} + \ldots\ldots \tag{1}$$

where: p_o is the average market price in year t = o, the present
e_t is the earnings per share in year t
r_o is the discount rate

If one assumes that $e = e_1 = e_2 \ldots . e_n \ldots .$ then

$$p_o \approx \frac{e}{r_o} \tag{2}$$

Investors will have varying expectations concerning the growth in earnings per share; but it seems that they would be aware of the earnings of the preceding year and the dilution that results from the current issue. Thus:

$$p_t \approx \frac{\dfrac{E(t-1)}{m(t-1) + \dfrac{N_t}{p_t}}}{r_t} \tag{3}$$

where: E(t—1) is the actual earnings available for common in year t—1
m(t—1) is the number of shares outstanding at the end of t—1
Nt is the dollar amount to be raised in year t; so that Nt/pt is the *number* of new shares.

Equation (3) can be manipulated to produce:

$$p_t \approx \frac{\dfrac{E(t-1)}{m(t-1)}}{r_t} - \frac{N_t}{m(t-1)} \tag{4}$$

Dividing through by b(t—1), the book value per share at the end of year t—1, one gets:

$$\frac{p_t}{b(t-1)} \approx \frac{\dfrac{E(t-1)}{m(t-1) \cdot b(t-1)}}{r_t} - \frac{N_t}{m(t-1) \cdot b(t-1)} \tag{5}$$

Equation (5) shows the ratio of market price to book value as a positive function of (a) the return on equity relative to the opportunity cost of capital and negatively related to (b) the dollar volume of new issues relative to the book value of existing equity.

Equation (5) was tested for the period 1962 through 1973, with the results below.

$$\frac{P}{B-1} = \underset{(49.26)}{0.891}\,\frac{E-1}{R} - \underset{(-1.93)}{0.921}\,\frac{N}{C-1}$$

$\bar{R}^2 = 0.955$
DW = 0.94

INTERVAL: 1962-1973; annual data.

where:

p	is the composite market price for Moody's 24 utilities. Source: *Moody's Public Utility Manual,* 1974.
B—1	is the book value per share (excluding reserves for deferred Federal income taxes and investment tax credits) for Moody's 24 utilities, lagged one year.
E—1	is the return to common equity for A and B investor owned utilities, lagged. Source: Federal Power Commission, *Statistics on Privately Owned Electric Utilities in the United States.*
R	is the yield on Moody's Aaa industrial bonds.
N	is the dollar volume of new public utility stock issues. This includes preferred and therefore is only a proxy for new common issues. Source: *Moody's Public Utility Manual* for A and B investor-owned utilities.
C—1	value of common equity, lagged. Source: Federal Power Commission, *Statistics of Privately Owned Electric Utilities in the United States.*

An alternative formulation assumes that the return to equity is modified by the investor's perception of the risk of the investment. To approximate this risk factor the coverage ratio was used. This is the ratio of earnings before interest charges and income taxes divided by interest. The lower this ratio, the greater the risk. The source was the Federal Power Commission, *Statistics on Privately Owned Electric Utilities in the United States.* The equation was estimated in logarithmic form over the interval 1962 through 1973.

$$\text{Log}\left(\frac{P}{B-1}\right) = \underset{(-3.07)}{-1.024} + \underset{(3.21)}{0.678}\ \text{Log}\left(\frac{E-1}{R}\right) + \underset{(2.37)}{0.939}\ \text{Log}\,(\text{COV-1})$$

$\bar{R}^2 = 0.942$; normalized $\bar{R}^2 = 0.956$

DW = 1.34; normalized DW = 1.36

Appendix C

Regressions to Explain the Decline in Market Price Relative to Book Value — Individual Utilities

These regressions use time series data pooled across the 71 utilities. In such regressions the observations are values for a number of utilities, each over several years. The key assumption is that the same relationships hold both among firms and over time. Several variations are possible. In the simplest version one assumes the identical relationship for all firms and employs a single constant. The form of the regression in this case is:

$$Yit = a + bXit$$

where Yit is the dependent variable for utility i at time t. Xit is the independent variable for utility i at t. a and b are the same for each utility. Alternatively one may try to take account of systematic variation among the utilities with individual constants, essentially dummy variables. Thus:

$$Yit = ai + bXit$$

It is also possible to perform a version of generalized least squares, which in addition to having multiple constants also considers the possibility of correlation among the error terms, implying that what happens to one firm influences the performance of another. When tried, these produced results very similar to those in the multiple constant version. The same variables were significant but their coefficients were closer to those in the simple single constant version and the explanatory power of the equations was slightly reduced.

The hypothesis was that the ratio of price to book value is primarily a function of the relationship between the return to equity and the yield on alternative investments, as represented by interest rates. Because it is generally thought that purchasers of utility stocks are interested more in income than in appreciation, the possibility that dividends rather than earnings are viewed as the "return" was also considered. Coverage ratios were introduced to represent a measure of perceived risk, with low values indicating both general poor health of the company and the possibility that dividends might be skipped. Finally, because information on desired equity funding was not available, the percentage increase in shares was used to take account of any saturation effects and fears of earnings dilution.

The best equations appear in Table 7 of the article and are starred in this appendix. In general, the versions with multiple constants and current values of the independent variables perform most successfully.[49] However,

[49]The percentage change in shares used currently may introduce a slight bias. However this variable functions primarily as a dummy and has almost the same coefficient and significance when used currently as when it is lagged.

all variations support the hypothesis that the return to equity relative to the yield on alternative investments is the key determinant of the ratio of market price to book value.

For each equation the mean absolute error was calculated for the New England firms and found to be approximately the same percentage of the average ratio of price to book value as for the entire sample. Thus conclusions based on these regressions are valid for the New England region as well as for the industry. These ratios appear under each equation.

Lastly, it is interesting to note that in all these equations the individual constants for the New England firms are somewhat below the industry average. This suggests that the market discounts these stocks somewhat more than the financial variables warrant. While this discount may be related to size, it also seems to reflect perceptions of regulatory climate. Utilities in Texas and Oklahoma where regulation is minimal have relatively large constants indicating that the market pays a premium for their stocks.

Equations

* — indicates preferred equation. These appear in Table 7 of the article.
ci — designates multiple constants. These are listed after each equation.

The individual utilities are identified.

INTERVAL 1965-1974

1) $$\frac{P}{B-1} = -0.370 + 1.036 \left(\frac{E\#}{R}\right)_{-1}$$

$$(-7.16) \quad (42.29)$$

$\bar{R}^2 = 0.72$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.236}{1.368} = .17$ U.S. $\frac{.300}{1.731} = .17$

2) $$\frac{P}{B-1} = ci + .975 \left(\frac{E\#}{R}\right)_{-1}$$

$$(47.34)$$

$\bar{R}^2 = 0.76$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.179}{1.368} = .13$ U.S. $\frac{.208}{1.731} = .12$

Utility	Mean Absolute Error	Constant	Utility	Mean Absolute Error	Constant
PBVBSE	0.09750	—0.31623	PBVDTE	0.18411	—0.38405
PBVCTP	0.19630	—0.43534	PBVIPL	0.26542	—0.44421
PBVEUA	0.26968	—0.38231	PBVOEC	0.21197	—0.36901
PBVNES	0.12917	—0.33501	PBVPIN	0.18103	—0.04344
PBVNEG	0.17563	—0.36731	PBVSIG	0.24747	—0.63643
PBVNU	0.18356	—0.35097	PBVTED	0.14526	—0.40310
PBVPNH	0.16961	—0.46334	PBVWPC	0.22998	—0.41740
PBVUIL	0.21298	—0.49831	PBVWPWR	0.16121	—0.40087
PBVAYP	0.17383	—0.47481	PBVIPW	0.16486	—0.33370
PBVATE	0.20449	—0.17404	PBVIOP	0.20825	—0.47038
PBVCNH	0.19982	—0.48661	PBVIUTL	0.19167	—0.52114
PBVED	0.15797	—0.29246	PBVKLT	0.11855	—0.43771
PBVDQU	0.17004	—0.46931	PBVMPL	0.12812	—0.56958
PBVGPU	0.21775	—0.38906	PBVNSP	0.09752	—0.39947
PBVLIL	0.17395	—0.28340	PBVOTTR	0.18010	—0.55142
PBVNGE	0.17411	—0.48122	PBVSAJ	0.13939	—0.47494
PBVPPL	0.13748	—0.39767	PBVUEP	0.16826	—0.32147
PBVPE	0.17379	—0.28259	PBVEDE	0.16086	—0.41084
PBVBGE	0.20252	—0.33248	PBVKU	0.15422	—0.48348
PBVCPL	0.35659	0.09031	PBVCEL	0.32572	0.25377
PBVDEW	0.23604	—0.23924	PBVCSR	0.26943	0.13817
PBVDUK	0.27263	0.09317	PBVHOU	0.35313	0.45690
PBVFDP	0.32299	0.15047	PBVOGE	0.21525	0.13648
PBVFPL	0.33294	0.26136	PBVSPS	0.29399	0.14654
PBVPOM	0.15890	—0.32692	PBVTXU	0.26178	0.48294
PBVSAV	0.15054	—0.29151	PBVTGE	0.28978	—0.15150
PBVSCG	0.16181	—0.03990	PBVAZP	0.18091	—0.12910
PBVSO	0.17228	—0.05637	PBVIDA	0.19711	—0.20003
PBVTE	0.42534	0.52790	PBVNVP	0.34836	—0.01720
PBVVEL	0.30778	—0.02394	PBVPNM	0.28556	—0.28957
PBVAEP	0.27892	—0.06054	PBVSRP	0.31763	0.01046
PBVCER	0.18416	—0.40806	PBVUTP	0.13107	—0.39787
PBVCIP	0.17780	—0.46716	PBVPPW	0.19372	—0.29183
PBVCVX	0.26664	—0.50526	PBVPGN	0.15690	—0.39057
PBVCWE	0.15092	—0.21976	PBVPSD	0.10617	—0.26477
			PBVSCE	0.15465	—0.26807

3)* $$\frac{P}{B-1} = ci + 1.039\,\frac{E}{R}$$
(55.77)

$\bar{R}^2 = 0.81$

Ratio of mean absolute error to average ratio of price to book value:

New England $\dfrac{0.196}{1.368} = 0.14$ U.S. $\dfrac{0.194}{1.731} = 0.11$

Utility	Mean Absolute Error	Constant	Utility	Mean Absolute Error	Constant
PBVBSE	0.08702	—0.35527	PBVDTE	0.12518	—0.38497
PBVCTP	0.19658	—0.44433	PBVIPL	0.18097	—0.46950
PBVEUA	0.33055	—0.36931	PBVOEC	0.20919	—0.38037
PBVNES	0.12558	—0.38261	PBVPIN	0.19097	—0.13946
PBVNEG	0.20048	—0.41988	PBVSIG	0.18071	—0.75218
PBVNU	0.15837	—0.40630	PBVTED	0.14393	—0.46384
PBVPNH	0.19774	—0.52032	PBVWPC	0.19869	—0.46825
PBVUIL	0.27066	—0.59387	PBVWPWR	0.17730	—0.45365
PBVAYP	0.11451	—0.49458	PBVIPW	0.11411	—0.31560
PBVATE	0.26798	—0.26215	PBVIOP	0.12833	—0.51597
PBVCNH	0.16852	—0.49436	PBVIUTL	0.13759	—0.60822
PBVED	0.12116	—0.32670	PBVKLT	0.10248	—0.43569
PBVDQU	0.17678	—0.52604	PBVMPL	0.11333	—0.57124
PBVGPU	0.12478	—0.37571	PBVNSP	0.06811	—0.43601
PBVLIL	0.13868	—0.32940	PBVOTTR	0.17474	—0.58874
PBVNGE	0.17797	—0.50185	PBVSAJ	0.16529	—0.48796
PBVPPL	0.12518	—0.47707	PBVUEP	0.10662	—0.32857
PBVPE	0.12526	—0.32398	PBVEDE	0.13721	—0.42617
PBVBGE	0.11194	—0.42505	PBVKU	0.19476	—0.47746
PBVCPL	0.37263	0.07696	PBVCEL	0.37400	0.14090
PBVDEW	0.23998	—0.28904	PBVCSR	0.21351	0.06521
PBVDUK	0.24345	0.08684	PBVHOU	0.30499	0.42812
PBVFDP	0.26351	0.11035	PBVOGE	0.13390	0.09127
PBVFPL	0.36102	0.20356	PBVSPS	0.34935	0.09490
PBVPOM	0.17529	—0.38379	PBVTXU	0.24853	0.41644
PBVSAV	0.09905	—0.30438	PBVTGE	0.30660	—0.25553
PBVSCG	0.14180	—0.05513	PBVAZP	0.29645	—0.19763
PBVSO	0.18604	—0.10262	PBVIDA	0.16686	—0.27332
PBVTE	0.43756	0.47571	PBVNVP	0.34314	—0.09144
PBVVEL	0.33836	—0.06634	PBVPNM	0.26646	—0.35372
PBVAEP	0.29869	—0.13033	PBVSRP	0.32249	—0.05859
PBVCER	0.10676	—0.43423	PBVUTP	0.09214	—0.46481
PBVCIP	0.16567	—0.44379	PBVPPW	0.14546	—0.33509
PBVCVX	0.16652	—0.44085	PBVPGN	0.12044	—0.44726
PBVCWE	0.12631	—0.22798	PBVPSD	0.11727	—0.34838
			PBVSCE	0.19048	—0.35327

INTERVAL 1968-1974, 497 observations

$$4)\quad \frac{P}{B-1} = ci + .720\left(\frac{E\#}{R}\right)_{-1} + .070\ \text{COV-1} - 0.806\ \text{NS-1} + 0.731\ \text{PO-1}$$

$$(12.35)\qquad (3.93)\qquad (-2.95)\qquad (5.54)$$

$\overline{R}^2 = 0.58$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.144}{1.218} = .118$ U.S. $\frac{.183}{1.454} = .126$

Utility	Mean Absolute Error	Constant	Utility	Mean Absolute Error	Constant
PBVBSE	0.10149	—0.64003	PBVDTE	0.17174	—0.68792
PBVCTP	0.10721	—0.78505	PBVIPL	0.22558	—0.69581
PBVEUA	0.16346	—0.70795	PBVOEC	0.17595	—0.76809
PBVNES	0.12454	—0.64740	PBVPIN	0.14691	—0.44927
PBVNEG	0.14633	—0.65024	PBVSIG	0.16074	—0.80002
PBVNU	0.19872	—0.58080	PBVTED	0.10065	—0.64978
PBVPNH	0.17202	—0.64229	PBVWPC	0.16688	—0.71408
PBVUIL	0.13683	—0.74980	PBVWPWR	0.16706	—0.69935
PBVAYP	0.19517	—0.65964	PBVIPW	0.10721	—0.69758
PBVATE	0.17715	—0.45528	PBVIOP	0.15687	—0.79679
PBVCNH	0.11696	—0.74280	PBVIUTL	0.17572	—0.85849
PBVED	0.12847	—0.64587	PBVKLT	0.09054	—0.73937
PBVDQU	0.16117	—0.63247	PBVMPL	0.10346	—0.77118
PBVGPU	0.13829	—0.60637	PBVNSP	0.11198	—0.63445
PBVLIL	0.16281	—0.57002	PBVOTTR	0.10007	—0.80254
PBVNGE	0.11605	—0.69121	PBVSAJ	0.10408	—0.68785
PBVPPL	0.11372	—0.59335	PBVUEP	0.13028	—0.61797
PBVPE	0.10897	—0.59817	PBVEDE	0.12992	—0.67544
PBVBGE	0.16643	—0.64603	PBVKU	0.16634	—0.84154
PBVCPL	0.21716	—0.37537	PBVCEL	0.37564	—0.00119
PBVDEW	0.17844	—0.58158	PBVCSR	0.25927	—0.22958
PBVDUK	0.23594	—0.34126	PBVHOU	0.38132	0.12863
PBVFDP	0.34703	—0.13392	PBVOGE	0.20250	—0.22864
PBVFPL	0.29284	0.00613	PBVSPS	0.15015	—0.39090
PBVPOM	0.13845	—0.53989	PBVTXU	0.26623	0.14633
PBVSAV	0.15063	—0.57247	PBVTGE	0.21878	—0.40924
PBVSCG	0.23058	—0.32936	PBVAZP	0.09572	—0.41895
PBVSO	0.16377	—0.37937	PBVIDA	0.12324	—0.49942
PBVTE	0.41389	0.16086	PBVNVP	0.34871	—0.10244
PBVVEL	0.20675	—0.38916	PBVPNM	0.23681	—0.51061
PBVAEP	0.26298	—0.32364	PBVSRP	0.36328	—0.22588
PBVCER	0.16189	—0.68208	PBVUTP	0.10213	—0.59145
PBVCIP	0.11807	—0.73581	PBVPPW	0.14721	—0.45269
PBVCVX	0.53575	—1.00129	PBVPGN	0.15059	—0.54020
PBVCWE	0.15418	—0.58881	PBVPSD	0.13361	—0.54108
			PBVSCE	0.16895	—0.53394

$$5)^*\quad \frac{P}{B-1} = ci + 1.205\ \frac{E}{R} + .062\ \text{COV-1} - 0.811\ \text{NS} + 1.124\ \text{PO}$$

$$(24.34)\qquad (5.19)\qquad (-4.75)\qquad (10.21)$$

$\overline{R}^2 = 0.74$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.106}{1.218} = .087$ U.S. $\frac{.144}{1.454} = .099$

Utility	Mean Absolute Error	Constant	Utility	Mean Absolute Error	Constant
PBVBSE	0.06709	—1.57955	PBVDTE	0.07644	—1.56155
PBVCTP	0.04861	—1.67876	PBVIPL	0.15790	—1.80135
PBVEUA	0.09954	—1.60041	PBVOEC	0.09720	—1.85154
PBVNES	0.09747	—1.57033	PBVPIN	0.12946	—1.56409
PBVNEG	0.12611	—1.56979	PBVSIG	0.09022	—1.91555
PBVNU	0.10470	—1.57146	PBVTED	0.09307	—1.75752
PBVPNH	0.09554	—1.56904	PBVWPC	0.10513	—1.56626
PBVUIL	0.20554	—1.81443	PBVWPWR	0.16235	—1.67582
PBVAYP	0.14623	—1.70177	PBVIPW	0.06592	—1.66420
PBVATE	0.19529	—1.57480	PBVIOP	0.11641	—1.79068
PBVCNH	0.12178	—1.64358	PBVIUTL	0.15885	—1.90254
PBVED	0.05893	—1.34400	PBVKLT	0.09170	—1.64276
PBVDQU	0.09517	—1.78049	PBVMPL	0.09482	—1.79124
PBVGPU	0.12510	—1.51326	PBVNSP	0.07334	—1.66949
PBVLIL	0.10169	—1.55730	PBVOTTR	0.08695	—1.72781
PBVNGE	0.09674	—1.60500	PBVSAJ	0.07548	—1.59993
PBVPPL	0.14330	—1.61386	PBVUEP	0.04999	—1.56677
PBVPE	0.09233	—1.55947	PBVEDE	0.13041	—1.72016
PBVBGE	0.10847	—1.65990	PBVKU	0.13143	—1.75579
PBVCPL	0.19892	—1.27562	PBVCEL	0.36984	—1.21010
PBVDEW	0.09462	—1.60485	PBVCSR	0.17633	—1.38291
PBVDUK	0.12653	—1.19147	PBVHOU	0.23823	—0.89580
PBVFDP	0.27552	—1.12857	PBVOGE	0.13678	—1.40401
PBVFPL	0.26274	—0.94869	PBVSPS	0.12244	—1.69672
PBVPOM	0.20073	—1.40377	PBVTXU	0.18736	—0.91524
PBVSAV	0.06634	—1.51545	PBVTGE	0.17665	—1.41230
PBVSCG	0.17361	—1.31783	PBVAZP	0.18489	—1.33303
PBVSO	0.15567	—1.34530	PBVIDA	0.12087	—1.46508
PBVTE	0.41096	—0.80804	PBVNVP	0.33727	—1.02955
PBVVEL	0.18575	—1.31021	PBVPNM	0.22978	—1.47267
PBVAEP	0.20366	—1.50422	PBVSRP	0.29394	—1.20377
PBVCER	0.06844	—1.65446	PBVUTP	0.07266	—1.51371
PBVCIP	0.08583	—1.74718	PBVPPW	0.08552	—1.48316
PBVCVX	0.32139	—1.96714	PBVPGN	0.10842	—1.55724
PBVCWE	0.09097	—1.56370	PBVPSD	0.12461	—1.38326
			PBVSCE	0.20731	—1.40324

$$6)\ \frac{P}{B-1} = ci + \underset{(15.25)}{1.193}\left(\frac{D}{R}\right)_{-1} + \underset{(3.64)}{0.058}\ COV\text{-}1 - \underset{(-4.12)}{1.046}\ NS\text{-}1$$

$\bar{R}^2 = 0.61$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.139}{1.218} = .14$ U.S. $\frac{.175}{1.454} = .121$

Utility	Mean Absolute Error	Constant	Utility	Mean Absolute Error	Constant
PBVBSE	0.12330	—0.31365	PBVDTE	0.17922	—0.36864
PBVCTP	0.10726	—0.45912	PBVIPL	0.21088	—0.38787
PBVEUA	0.16556	—0.41115	PBVOEC	0.14823	—0.58627
PBVNES	0.12158	—0.33496	PBVPIN	0.14661	—0.19649
PBVNEG	0.15307	—0.36451	PBVSIG	0.13716	—0.19240
PBVNU	0.17174	—0.31785	PBVTED	0.09571	—0.27723
PBVPNH	0.15721	—0.29110	PBVWPC	0.11310	—0.30083
PBVUIL	0.11350	—0.42782	PBVWPWR	0.11758	—0.38217
PBVAYP	0.17247	—0.31707	PBVIPW	0.11630	—0.49121
PBVATE	0.16434	—0.17996	PBVIOP	0.13445	—0.45460
PBVCNH	0.13983	—0.30636	PBVIUTL	0.16870	—0.34208
PBVED	0.13110	—0.27440	PBVKLT	0.12013	—0.32025
PBVDQU	0.19537	—0.54013	PBVMPL	0.15292	—0.33534
PBVGPU	0.13272	—0.32127	PBVNSP	0.15789	—0.36390
PBVLIL	0.16500	—0.21630	PBVOTTR	0.13192	—0.42300
PBVNGE	0.09247	—0.34616	PBVSAJ	0.12224	—0.35147
PBVPPL	0.10845	—0.30401	PBVUEP	0.13525	—0.41899
PBVPE	0.13950	—0.40835	PBVEDE	0.16673	—0.40176
PBVBGE	0.15950	—0.30811	PBVKU	0.14999	—0.40362
PBVCPL	0.17306	—0.03529	PBVCEL	0.27692	0.27099
PBVDEW	0.15790	—0.25699	PBVCSR	0.24212	0.10471
PBVDUK	0.23337	—0.00516	PBVHOU	0.37316	0.79861
PBVFDP	0.35161	0.39101	PBVOGE	0.20958	—0.02717
PBVFPL	0.23576	0.62789	PBVSPS	0.16643	—0.29910
PBVPOM	0.20231	—0.18462	PBVTXU	0.24196	0.68376
PBVSAV	0.15185	—0.33562	PBVTGE	0.18411	0.05560
PBVSCG	0.27367	0.00134	PBVAZP	0.06523	0.02584
PBVSO	0.16593	—0.05915	PBVIDA	0.11179	—0.10788
PBVTE	0.40092	0.66878	PBVNVP	0.35603	0.58860
PBVVEL	0.18191	0.01635	PBVPNM	0.18960	0.08861
PBVAEP	0.20065	—0.13875	PBVSRP	0.35002	0.21325
PBVCER	0.16295	—0.30287	PBVUTP	0.12476	—0.14013
PBVCIP	0.12800	—0.46729	PBVPPW	0.16982	—0.20107
PBVCVX	0.36283	—0.55684	PBVPGN	0.14056	—0.23558
PBVCWE	0.16627	—0.31737	PBVPSD	0.11179	—0.14378
			PBVSCE	0.17514	—0.07275

$$7)^*\ \frac{P}{B-1} = ci + \underset{(25.35)}{1.834}\ \frac{D}{R} + \underset{(4.80)}{0.057}\ COV\text{-}1 - \underset{(-3.33)}{0.567}\ NS$$

$\bar{R}^2 = 0.75$

Ratio of mean absolute error to average ratio of price to book value:

New England $\frac{.089}{1.218} = .073$ U.S. $\frac{.136}{1.454} = .094$

Utility	Mean Absolute Error	Constant	Utility	Mean Absolute Error	Constant
PBVBSE	0.09979	—0.92886	PBVDTE	0.09871	—0.93954
PBVCTP	0.06208	—1.08551	PBVIPL	0.17146	—1.10169
PBVEUA	0.08772	—1.05399	PBVOEC	0.08208	—1.44395
PBVNES	0.08717	—0.93923	PBVPIN	0.10866	—0.94937
PBVNEG	0.09916	—0.97688	PBVSIG	0.09768	—0.77725
PBVNU	0.09625	—0.95329	PBVTED	0.07778	—1.00352
PBVPNH	0.10139	—0.88402	PBVWPC	0.06702	—0.82973
PBVUIL	0.07645	—1.09286	PBVWPWR	0.10282	—1.05917
PBVAYP	0.13195	—0.96423	PBVIPW	0.08193	—1.18802
PBVATE	0.10629	—0.89096	PBVIOP	0.09109	—1.07259
PBVCNH	0.10471	—0.84481	PBVIUTL	0.15111	—0.95790
PBVED	0.10448	—0.64930	PBVKLT	0.08652	—0.87628
PBVDQU	0.18450	—1.32208	PBVMPL	0.05976	—0.95397
PBVGPU	0.09964	—0.92842	PBVNSP	0.08340	—1.02744
PBVLIL	0.11426	—0.85019	PBVOTTR	0.08513	—0.98850
PBVNGE	0.06379	—0.93554	PBVSAJ	0.07654	—0.92798
PBVPPL	0.09330	—0.92179	PBVUEP	0.08301	—1.03905
PBVPE	0.10548	—1.08408	PBVEDE	0.13913	—1.15121
PBVBGE	0.12589	—0.94441	PBVKU	0.10187	—0.97741
PBVCPL	0.18101	—0.62886	PBVCEL	0.21298	—0.46345
PBVDEW	0.09063	—0.90267	PBVCSR	0.17816	—0.63823
PBVDUK	0.15058	—0.58669	PBVHOU	0.29943	0.30476
PBVFDP	0.33936	—0.13834	PBVOGE	0.16491	—0.82223
PBVFPL	0.21308	0.19989	PBVSPS	0.11887	—1.23222
PBVPOM	0.26369	—0.71325	PBVTXU	0.17683	0.12772
PBVSAV	0.10319	—0.92726	PBVTGE	0.16320	—0.49002
PBVSCG	0.26247	—0.65327	PBVAZP	0.07490	—0.46999
PBVSO	0.19540	—0.67039	PBVIDA	0.09130	—0.68394
PBVTE	0.35779	0.12283	PBVNVP	0.34224	0.21017
PBVVEL	0.16248	—0.49625	PBVPNM	0.17907	—0.37196
PBVAEP	0.14282	—0.89925	PBVSRP	0.32634	—0.32691
PBVCER	0.10673	—0.93571	PBVUTP	0.08079	—0.66951
PBVCIP	0.09189	—1.18561	PBVPPW	0.05294	—0.90190
PBVCVX	0.32235	—1.32993	PBVPGN	0.08612	—0.89626
PBVCWE	0.09790	—0.98160	PBVPSD	0.07123	—0.60729
			PBVSCE	0.15359	—0.51295

Variables

p	– market price of common shares
B	– book value per share as of December 31
E	– the rate of return to equity as reported
E #	– the rate of return to equity as of December 31
D	– ratio of dividends to equity
R	– yield on Moody's Aaa industrial bonds
PO	– payout ratio
COV	– coverage ratio
NS	– percentage change in common shares (has not been multiplied by 100%)

All variables except R and COV have been calculated from data contained in *Valueline*. COV has been calculated using *Moody's Public Utility Manual.*

–1 designates a lag of 1 year.

Utilities by Region

New England

BSE	—Boston Edison
CTP	—Central Maine Power Company
EUA	—Eastern Utilities Associates
NES	—New England Electric System
NEG	—New England Gas and Electric Association
NU	—Northeast Utilities
PNH	—Public Service Company of New Hampshire
UIL	—United Illuminating Company

Mid-Atlantic

AYP	—Allegheny Power System
ATE	—Atlantic City Electric
CNH	—Central Hudson Gas and Electric Corporation
ED	—Consolidated Edison
DQU	—Duquesne Light Company
GPU	—General Public Utilities
LIL	—Long Island Lighting Company
NGE	—New York State Gas and Electric Corporation
PPL	—Pennsylvania Power and Light Company
PE	—Philadelphia Electric Company

South Atlantic

BGE	—Baltimore Gas and Electric Company
CPL	—Carolina Power and Light Company
DEW	—Delmarva Power and Light Company
DUK	—Duke Power Company
FDP	—Florida Power Corporation
FPL	—Florida Power and Light Company
POM	—Potomac Electric Power Company
SAV	—Savannah Electric and Power Company
SCG	—South Carolina Electric and Gas Company
SO	—Southern Company
TE	—Tampa Electric Company
VEL	—Virginia Electric and Power Company

East North Central

AEP	—American Electric Power
CER	—Central Illinois Light Company
CIP	—Central Illinois Public Service Company
CVX	—Cleveland Electric Illuminating Company
CWE	—Commonwealth Edison
DTE	—Detroit Edison
IPL	—Indianapolis Power and Light Company
OEC	—Ohio Edison
PIN	—Public Service Company of Indiana
SIG	—Southern Indiana Gas and Electric Company

TED —Toledo Edison
WPC —Wisconsin Electric Power
WPWR —Wisconsin Power and Light Company

West North Central
IPW —Interstate Power Company
IOP —Iowa Power and Light Company
IUTL —Iowa Southern Utilities
KLT —Kansas City Power and Light Company
MPL —Minnesota Power and Light Company
NSP —Northern States Power Company
OTTR —Otter Tail Power Company
SAJ —St. Joseph Light and Power Company
UEP —Union Electric Company
EDE —Empire Distric Electric

East South Central
KU —Kentucky Utilities Company

West South Central
CEL —Central Louisiana Electric Company
CSR —Central and South West Corporation
HOU —Houston Lighting and Power
OGE —Oklahoma Gas and Electric Company
SPS —Southwestern Public Service Company
TXU —Texas Utilities Company
TGE —Tucson Gas and Electric Company

Mountain
AZP —Arizona Public Service
IDA —Idaho Power Company
NVP —Nevada Power Company
PNM —Public Service Company of New Mexico
SRP —Sierra Pacific Power Company
UTP —Utah Power and Light Company

Pacific
PPW —Pacific Power and Light Company
PGN —Portland General Electric Company
PSD —Puget Sound Power and Light Company
SCE —Southern California Edison

Discussion

John W. Weber*

The author of the paper has stated the general problem faced by utilities very accurately and very succinctly. Briefly, it is that utilities face massive capital requirements with great dependence on external funding at a time when their ability to attract needed investment funds has eroded badly.

The reasons behind the general problem were treated adequately in the paper. For background, I restate them here in the manner I like to think about them. In the mid- to late-1960s, the utility industry began to feel the combined impact of four independent trends. First and most important, the Nation's chronic inflation picked up speed. The cost of money went up dramatically, and costs — both capital and operating — skyrocketed. Second, the environmental movement began to be felt. This brought both higher capital costs and costs due to delays in getting new plants on stream. Third, the growth of electrical peak load and energy consumption accelerated and became more uncertain. The result was a spurt in requirements for additional capacity. Last, the economies of scale in building ever-larger electrical generating facilities seemed to run out, and thus ended the offset to escalating construction costs.

The result was a much more difficult environment for utilities, and the author's documentation of the general problem — particularly with respect to the New England utilities — is good. Most of the paper, however, is devoted to the problem and its documentation, not to remedies. That is not to say that no list of suggestions for solutions appears in the paper — there is such a list. But the depth of work on the remedies does not generate confidence that they will solve the problem, rather than just provide a little relief. Some groups call for government guarantee of utility debt as the solution to the problem; others call for preferential tax treatment. Are regulatory commissions the only culprit? The appropriate strategy to resolve the financing difficulties of utilities turns on the root causes of the problem, together with an understanding of the improvements possible from all quarters. The paper contributed little of that.

*Senior Executive Consultant at Temple, Barker and Sloane. He is a professional engineer as well as an experienced business analyst, particularly for manufacturing and energy-related companies. He was previously Assistant Administrator for Operations, Regulations and Compliance in the Federal Energy Administration.

Remedies Proposed

So it is on possible solutions to the well-stated problem that I want to focus this discussion. Let us consider the implications of several sets of remedies: those put forth by the author, some coming out of Washington, and perhaps some thoughts pulled together in a different way or new to at least some of you.

All but a few serious observers of the utility industry understand that the individual companies must realize greater returns and greater cash flows than they now receive. There is, of course, disagreement over how much increased return is necessary, and especially over how to obtain this increased return. But many of the observers get tangled up sorting out the various remedies, and all seem to have an aversion to stating explicitly that electric bills will increase.

The author's list of remedies is centered around making realized rates of return competitive. It is very difficult to argue with that premise. The list includes four specific suggestions:

1. Raise allowed rates of return, starting first to enable the utilities to realize the return currently allowed by their commissions;
2. Base rate structures on cost estimates that take account of inflation, or on year-end figures rather than on historic costs;
3. Reduce regulatory lag, or at least adjust target rates to account for depressed earnings during the lag period;
4. Adopt a package of two points "proposed" by the utilities: include construction work in progress in the rate base and adopt normalized accounting in states where it is not now permitted.

Now that list of remedies is interesting — particularly the one to raise allowed rates of return — and all have some degree of merit. They have not been analyzed thoroughly, but even so are not dissimilar from those coming out of Washington. Consider two more lists of remedies:

1. The list from the President's Labor-Management Committee

   — Increase the investment tax credit
   — Include construction work in progress in the rate base
   — Depreciate construction work in progress
   — Allow accelerated depreciation
   — Provide deferred taxation for reinvested dividends

2. The list from the Congressional Budget Office

   — Adopt a replacement cost basis for assets
   — Adopt normalized accounting
   — Utilize current and future test years
   — Reduce regulatory lag
   — Eliminate discriminatory taxing

Notice that the great bulk of these remedies — certainly all those suggested by Lynn Browne — are aimed at generating greater return and cash flows by raising the price of energy to consumers. Notice that enabling a utility to realize the allowable rate of return, basing rates on up-to-date cost figures, reducing regulatory lag, including construction work in progress in the rate base, and permitting normalized accounting are all devices that increase utility revenues or cash flows by raising the rates their customers pay for their product. Notice particularly that no one called explicitly for rate hikes — only for things whose effect is to increase the unit price of energy.

Are all of us so afraid to advocate higher energy prices that we devise schemes to do exactly that, but then couch them in moralistic terms as if we were only assuring that the rate-making formula is just and equitable? The root problem is an inadequate return on equity to utilities. Why dance around the problem with suggestions that may have unwanted side effects? Including construction work in progress in the rate base, for instance, has the effect of charging current customers for future assets that will earn in the future — current energy prices would rise; future energy prices would be lower. Because of the tax situation, the procedure would also require $2 of revenues (all borne by customers) for every $1 realized by the utilities. How much simpler the entire process of relief would be if the regulatory commissions would grant an adequate return on equity to the utilities. The commissions have come miles, but for a variety of reasons stop short of granting an adequate return.

Spectrum of Remedies

In point of fact, there are only four ways utilities can increase their realized returns:

Raising the prices charged customers for energy
Obtaining government subsidies (in one form or another)
Selling more product
Operating more efficiently

And my guess is that the most efficient program to aid our ailing utilities includes something from each of those four.

1. *Raising prices.* Utilities on balance are realizing an 11-12 percent return on equity, a figure 3 or 4 percent too low in these inflationary times when the return on riskless securities has been pushed up to 8 or 9 percent. Now if the only way to attain a more realistic return on equity for utilities is to play games with such things as construction work in progress, replacement costs, and future test years so that regulatory commissions can retain low return on investment figures, then that is what we must do. But the niggardly returns have to stop not only because investor confidence in utility equities has been eroded, but because incentives for utility managements are wrong. Why should they work hard to achieve

cost reductions when regulatory commissions pass the benefits on almost immediately to customers? Further, there are subtle pressures on utility managements to make bad capital versus operating cost decisions. Why should they invest $600 per kilowatt for an efficient baseload plant at an inadequate return when they can invest much less on a peaking unit, knowing that the higher fuel costs of the peaker can be passed through immediately?

The financial problem could, of course, be alleviated by raising rates so high that customers effectively would be suppliers of capital. But that means current customers would be subsidizing future customers. A more reasonable approach is for commissions to allow a return that assures common stock will sell approximately at book value. That point reasonably balances the interests of customers and investors alike. Then the capital markets — not governmental agencies and procedures — will deal with investment and cash flow problems for the utilities. And the cost of providing that reasonable return amounts to a one-time rate increase of only about 8 percent, so you can see why I deplore the palliatives suggested in lieu of simply raising the return on equity to a fair level.

2. *Government subsidy.* Many types of Federal government actions can improve cash flow to utilities: investment tax credit, accelerated depreciation, guarantee of debt, and the elimination of double taxation are just a few of them. To some extent they are all a form of subsidy — a word which need not be thought of as pejorative. How you come down on the matter of government subsidy depends on your ideology: whether you believe the system — particularly the capital markets — will work, or whether you believe the government must make it work. It also depends on how you feel about the tax burden to be carried by utilities: should consumers of electricity and gas pay $2 for every $1 of realized return to the utility, the other $1 going to the government? Or is some different division of that government dollar appropriate? Any device that raises rates is a "twofer," and only governmental action can change that.

A second kind of government action — kind of a reverse subsidy — can be effective in aiding utilities. Many of the suggested remedies fall clearly within the jurisdiction of the state regulatory commissions and outside the realm of the Federal government, but the Federal government can persuade the commissions to follow desired policies. For example, to the extent that normalized accounting and the inclusion of construction work in progress in the rate base are important to the utility rescue operation, the government can withhold favored tax treatment or impose an effective excise tax on utilities in states regulated by recalcitrant commissions. Thus, almost any fair and equitable slate of remedies will include some role for the government.

3. *Selling more electricity.* In this age of "energy wastrels" and the "conservation ethic," selling more electricity or gas may sound like heresy. But

— assuming the electricity or gas is sold at a positive gross margin — selling more product is clearly a means open to utilities to generate more revenues and to realize higher returns. In addition, this is a path which requires no action by state regulatory commissions or by the government.

The challenge to utilities, of course, is not so much in selling more product as it is in selling "good" product. Selling off-peak electrical load, thereby improving load factor, can do wonders for profitability. It also has social and conservation benefits — for instance, using nuclear or coal-fired generating stations to supply electricity for heat storage devices that would otherwise burn gas or oil.

Any discussion of help for beleaguered utilities must consider self-help, and load factor improvement clearly falls in that category. Yet utility after utility continues to give lip service to load factor improvement without organizing to recognize this key factor to success. A high level concern for integrating all activities that affect load factor — marketing, customer education, public relations, and rate design — is still the exception throughout the industry. Improving load factor is no easy task but it is lucrative. A 1 percent improvement in load factor — which for most utilities has been deteriorating for years as growth in peak demand outpaced growth in energy sales — will increase the net income available for common stock of an electric utility about 11 or 12 percent. Such an effort is clearly worth making, and should be considered a vital, integral part of any rescue plan for utilities.

4. *More efficient operations.* A final way to increase the realized returns to utilities is to improve their operations — to make them more efficient, more effective. Improving operations implies a management process of continued performance evaluation and audit both for the large scale, relatively infrequent policy actions and for the small scale, frequent decisions made all over the organization. Many utilities have yet to formalize such a process.

The point here is that putting one's own house in order generates increased returns; it also provides a convincing rebuttal to the charges of "country club management" often leveled at utilities, thereby improving the chances of being granted rate relief when requested. No slate of remedies for the utility industry can be complete without such a role for the individual companies themselves.

Where Do We Go?

What does all this mean? It means that alleviating the ills of the industry entails work for far more than just regulatory commissions. Without question the commissions have a full slate of tasks, but the government and the individual utilities also have a major role. Specifically, the roles can be described briefly as follows:

1. *Commissions.* The regulatory commissions simply must raise allowable returns so that utility returns are in line with the requirements of the

capital markets. Otherwise, the securities will sell at a discount to book value, and the current problems will be perpetuated. If euphemistic devices are needed to subvert the intense political pressures against raising allowable returns, they should be utilized. What is needed, however, is a competitive return on equity.

The regulatory commissions also must consider changing the nature of their involvement with the utilities they regulate. If regulation is to be nonmechanistic, commissions must develop the in-depth knowledge and skills to be discriminating questioners of utility managers, insightful readers of reports, knowledgeable buyers of expert service, and particularly evaluators of managerial performance. Then instead of mediocre returns for all utilities, the regulators could penalize undistinguished management with undistinguished returns on investment, and they could reward outstanding performance with outstanding returns. One could envision a system in which poorly managed utilities were granted a 10 percent return on equity, middle-ground utilities were granted 13 percent, and outstandingly managed utilities were granted 16 percent. Such a reward-oriented system could provide the utility industry with capitalistic incentives — no longer would the rewards of good management be turned over to the customers; rather, customers, shareholders, and management would all participate in the benefits. This idea is a clear departure from current practice. It would require effective regulators who could stand up to political pressure, who understand the economics of the business, who are willing to base decisions on solid analysis, and who will take effective action.

2. *Government.* The Federal government's role is two-fold. First, it must provide leadership in resolving the problems of the utility industry. Like it or not, many states look to the government to resolve many kinds of overall issues, including, for instance, the impact of peak-load pricing on load factors. This does not relieve others from responsibility for studying opportunities to resolve problems, but the government clearly has the lead. Second, the government has the job of sorting out national priorities and equities in the matter of subsidy-type programs. If rates are increased, is the $2 for $1 ratio appropriate? How much pressure should be put on the individual states to comply with such goals as normalized accounting or including construction work in progress in the rate base?

3. *Individual utilities.* There are three separate tasks the individual utilities must carry out to help themselves. First, they must become lean, hungry organizations — constantly on the lookout for profit improvement opportunitites. Second, they must sell more "good" product. As demand increases, they must work to reverse the deteriorating trend in load factor. Finally, they must learn how to attract and motivate the kind of management needed to run these companies. Times have changed, the job of management has changed, and the kind of manager needed has changed. Utilities must recognize that and move to meet that challenge.

The tasks outlined for the commissions, the goverment, and the individual utilities are not mutually exclusive. To the contrary, they require coordination and integration. Most important, each of the participants in the rescue process must demonstrate an understanding of the job the others have to do. A contrary example may illustrate the importance of understanding and coordinated action. The California Public Utilities Commission recently ruled to disallow all executive salaries in excess of $100,000 at Pacific Gas & Electric. While in the abstract that figure represents a handsome salary, the action shows little appreciation for the realities of an executive compensation structure or for the personnel development chore of a large utility. Should PG&E elect to limit top salaries to the allowed level, compensation throughout the organizational pyramid will be low. The likely result is that the better people will depart for higher paying jobs, or probably not join the company in the first place. That leaves less talented executives to inherit the key jobs — just at a time when the changed nature of the utility business is demanding better and better executives.

Finally, in carrying out their tasks all three participants must utilize thorough and imaginative analysis. The lists of remedies for the utility industry include many alternatives, each with its proponents and detractors. And the utility system is complex and interrelated — when one element is changed, often many others are affected, and the net result is not always obvious. Electrical peak-load pricing sounds so rational, but it will be no bargain if it generates severe needle peaks. In a similar fashion, liberalized depreciation policies or an investment tax credit may affect the actual level of capital expenditures in odd ways. Only with really good analysis are the proper strategies likely to be selected.

Discussion

Andrew F. Brimmer*

I would normally think that the fact that I'm now teaching at the Harvard Business School would be sufficient identification and would provide me with a cloak of legitimacy, but given the criticism I heard this morning about academics and bureaucrats who work inside offices, it occurred to me I should minimize the risk of being thought less able and suggest some additional basis for my standing here. I say this proudly and seriously because I do think we need to broaden the sources of information on which we are placing both analyses and judgments about the financing problems of public utilities. Now in addition to teaching at Harvard Business School I wear a couple of other hats.

One, I am director and economic advisor at a large chemical company, which uses a lot of energy. Not only is the energy provided by petroleum and natural gas, but in many places the company is the biggest customer of the local electric utility. Secondly, working with the company's economists I try to make some judgments about the long-run demand for and supply of oil energy in the United States, not simply that generated by electric utilities. I have some comments on that because the implication of the forecast made by the company's analysts casts a bit of doubt on the expected strength of demand for energy over the next decade at least. Currently I also sit on two investment committees. One committee meets once every two weeks and makes judgments about what to do with an enormous amount of money, and I assure you we are discounting heavily the prospects of public utilities, especially electric utilities, and little or no money is going in that direction. If anything, we are selling our utility bonds. The other committee is doing a similar kind of thing. I mention this because the capital market and the capital market's perception of the utility problem is a subject to which I want to address most of my remarks this morning. And finally I spend a lot of time with bankers, more now with commercial bankers than central bankers, and what they are telling me suggests an additional dimension of the financing problems faced by public utilities. Now if you think that's sufficient authority to speak on this subject — I will pause for a moment unless I am told to sit down — I'll proceed. Since I heard a laugh and not an indication to sit down, I'll proceed.

*Thomas Henry Carroll Ford Foundation Visiting Professor at the Harvard Business School. He has held a wide variety of university and government positions including more than eight years as a member of the Board of Governors of the Federal Reserve System. He specializes particularly in studies of capital markets.

The author of this paper sets out to achieve two objectives. The first aim is to provide an assessment of the experience of investor-owned electric utilities in New England in recent years. This goal requires as background an appraisal of the experience of electric utilities in the national economy. In particular, the author focuses on the industry's capital requirements, its growing dependence on external sources of funds, and the progressive weakening of its ability to attract investment funds — with special emphasis on its extremely limited ability to market common stock.

New England Experience

I have no basis for comment on the author's treatment of the New England experience. Although I have been concerned with — and have written a few papers on — the financing problems of public utilities, my own work has dealt with the issues in the national context. Consequently, I must take the author at her word as far as the experience of New England's public utilities is concerned. Yet, some of the variations in the New England picture sketched by the author (such as their relatively greater expenditures for the construction of nuclear power facilities) strike me as entirely consistent with trends in the Nation as a whole.

However, if I had been looking at New England explicitly, I would have put greater emphasis on the adverse impact which "consumerism" seems to have had on the public utility rate-making process in New England. In the spring of 1974, while I was still a member of the Federal Reserve Board, I conducted an informal survey (with the help of economists in the regional Federal Reserve Banks) of public utilities in order to get a feeling for "...the extent to which the regulators of public utilities at the Federal, state, and local levels appreciate the scope of the financing difficulties faced by public utilities and are responding to the need to assure a sounder financial base..." Of the 98 public utilities contacted in that survey, 20 were in New England. Forty-two of the total were electric utilities, and nine of these were in New England. There were also 25 combination gas and utility firms, and three of these were in New England. The responses to the survey suggested strongly that — at least into the spring of 1974 — public utility commissions had been extremely slow in responding to the requests for rate adjustments. The experience in New England was essentially the same as that for the Nation as a whole.[1]

In the last year, while public utility commissions seem to have become somewhat more responsive to the financial problems faced by the firms they regulate, organizations representing consumers seem also to have become stronger. With rare exceptions, their influence has been exerted in the direction of holding down the size of the rate increases actually approved. The latest example of this occurred here in Massachusetts a few

[1]See Andrew F. Brimmer, "Public Utility Pricing, Debt Financing, and Consumer Welfare," presented before the Wharton School Club of Washington, D.C., May 22, 1974.

days ago. According to newspaper reports, Boston Edison sought a $70 million rate increase. Instead, the State Department of Public Utilities approved an increase of only $26.7 million. Now on the record we know that commissions don't usually give applicants all they ask for but roughly 40 or 50 percent and in a few cases as high as 60 percent seems about in the ball park. So one could have thought some $35 to $40 million or thereabouts could have been expected in the terms of this application instead of the amount granted; the increase granted was only $26.7 million. More importantly, the Department exempted the first 384 kilowatt hours of residential use per month from the allowed increase. In so doing, it clearly was responding — at least partially — to the campaign of the Citizens Action Program on Energy (CAPE), a consumer action group. A central part of CAPE's program was the introduction of a so-called "lifeline supply" of electricity under which residential users would pay a flat rate for the first 300 kilowatt hours of residential use per month. While the Department rejected this concept, its decision to exempt the 384 kilowatt hours from the allowed rate increase was a step in CAPE's direction. Moreover, the Department allowed rate increases of $5.1 million for the New Bedford Gas and Edison Light Company and $1.1 million for Cambridge Electric Light Company, but neither of the latter two increases included an exemption for residential customers. So not only is the bow in the direction of CAPE explicit, it is discriminatory, and it clearly suggests that the big companies are the ones likely to have to bear this kind of additional burden.

Again, when we attempt to appraise the outlook for public utilities — in New England as well as the Nation as a whole — I think it is important that we give considerable weight to the probable impact of the consumer movement. My hunch is that the effects will be adverse to the utilities in the short run — and to consumers themselves in the long run.

National Experience

Let me now turn to the experience of electric utilities in the national context. Here I would like to make several points. The author of the paper uses the forecast of electricity demand and capital requirements developed by a committee of the Edison Electric Institute (EEI). This committee estimated that, from 1974 through 1990, the consumption of electric energy (measured in kilowatt hours) will expand at an annual rate of 5.3 to 5.8 percent. To meet this goal, construction expenditures would have to rise by 10 percent per year. On the basis of this forecast, the author agrees that the industry's capital requirements will indeed be enormous.

I do not wish to quarrel with this general conclusion. However, I think the demand for electricity — and capital requirements — may grow at a rate somewhat less than the range suggested by EEI. Of course, the EEI committee itself stressed that the growth in demand is likely to fall considerably short of the high rate recorded in recent years — e.g., 7.9 percent from 1960-73. The reduction can be traced to both the substantially higher price of energy and intensified conservation efforts.

I would like to stress an additional factor. This is the further decrease in the amount of energy required to produce a given volume of real output in the Nation as a whole. In 1947, it took 33.0 quadrillion Btus of primary energy to produce $309.9 billion of real gross national product (measured in 1958 dollars). (Here primary energy is defined as the aggregation of oil, natural gas, coal, hydro, and nuclear energy.) Thus, in 1947, the energy-GNP ratio was 106.5. In 1973, the consumption of primary energy amounted to 75.6 quadrillion Btus. Real GNP in that year amounted to $839.2 billion. Thus, the energy-GNP ratio was 90.1. A recent forecast (prepared by a large chemical company) of energy and output in the United States for the year 1985 put primary energy consumption in that year at 96.0 quadrillion Btus. Real GNP was projected at $1,170.0 billion — yielding an energy-GNP ratio of 82.1. The historical figures presented here represent an annual rate of increase of 3.1 percent in primary energy consumption during the 1947-73 period. The growth rate for real GNP was 3.9 percent, and the energy-GNP ratio declined by 0.6 percent per year. Over the forecast period 1973-85, primary energy consumption is projected to increase at an annual rate of 2.0 percent and real GNP is projected to rise at an annual rate of 2.8 percent. Thus, the energy-GNP ratio might decline by 0.8 percent per year.

The above estimates suggest to me that energy demand might grow less rapidly over the next decade because of continued increases in the efficiency of energy consumption in American industry. Furthermore, I would presonally doubt the likelihood of real GNP growing at an annual rate as high as 3.7 percent during the next 10 to 15 years. Instead, I would expect the higher price of energy (as well as actual shortages of natural gas) along with a long-run decline in labor productivity will most likely result in an annual rate of increase in real GNP over the next decade substantially below the 3.7 percent per year which underlies EEI's projection of energy consumption and electric utilities' capital requirements.

Electric Utilities in the Capital Market

The author of the paper also comments briefly on the problems posed by the increased reliance of electric utilities on external funds to meet their construction requirements. I agree with her general conclusions in this regard — especially with the emphasis on the constraints on equity financing arising from the fact that the market price of their common stocks has typically been so far below book value in recent years. Last June, I made a comprehensive analysis of the financing problems of public utilities.[2] The results of my own work amplify and extend the conclusions presented (briefly) by the author of the paper being discussed

[2]See "Financing Public Utility Investment Requirements," presented before the 43rd Annual Convention of the Edison Electric Institute, Denver, Colorado, June 3, 1975.

here. Consequently, I thought it might be helpful if I were to summarize the highlights of the paper I presented last summer:

— While electric utilities obtained over half of their total funds from internal sources a decade ago, less than one-third is generated internally today. Especially noteworthy is the fact that retained earnings provide only one-tenth of their requirements now compared with one-fifth ten years ago.
— The counterpart of this trend is increased reliance on the capital market. External funds have risen from about 40 percent to 70 percent of the total. The share of common stock climbed steadily from 6.6 percent in 1964 to 19 percent in 1973 — although the fraction dropped to 12 percent last year.
— The share of long-term debt rose from under one-third in 1964 to one-half in 1970; eased off to one-third in 1972, and climbed again to almost one-half of total funds raised last year.
— In the last few years, as they encountered difficulties selling long-term bonds, electric utilities have been forced to rely more heavily on temporary accommodations. Their short-term debt has risen from about 3.2 percent of total capitalization in 1971 to 5.7 percent in 1974.
— In the same vein, electric utilities have become noticeably more dependent on commercial banks. For example, electric utilities had borrowed 3.8 percent of the banks' commercial and industrial loans outstanding in April 1970. The fraction had climbed to 6.0 percent in April 1974, and it rose further to 7.2 percent in April of this year. Moreover, electric utilities have accounted for an even larger share of the banks' term loans (five to seven years in maturity) in recent years: 3.2 percent in 1970; 7.3 percent in 1974, and 8.3 percent in April of this year. Over this five-year period, about 18 percent of the net increase in commercial banks' term loans went to electric utilities.
— Reflecting increased reliance on external funds, public utilities have become a much more important force in the capital market. In 1964, they offered one-fifth of the new corporate bonds and stocks sold; by 1974 their share had climbed to one-third of the total. Their share of new stocks alone was even larger — in the neighborhood of two-fifths in 1972-73 and three-fifths in 1974-75. In contrast, while electric utilities were becoming a more powerful force in the capital market, gas and telephone were declining relatively.
— As is generally known, electric utilities remain much more dependent on public flotations of securities than do gas companies. The reasons are clear: regulatory posture in most states and better identification of most electric companies in the capital market. But the continued preference of electric utilities for very long bond maturities and the dislike of sinking fund arrangements also diminish the attractiveness of electric utility bonds to many life insurance companies who handle a sizable proportion of the direct placements.

— So, electric utilities are necessarily forced into the role of necessitous borrowers in the public capital market with few alternatives. Consequently, they have to give what the market demands — if they are to obtain funds. And what the market has demanded over the last year is a sizable interest premium. For example, in March 1974, new issues of high grade public utility bonds were yielding 165 basis points more than long-term U.S. Government bonds. After Consolidated Edison omitted its dividend in April last year, the interest rate differential jumped dramatically and rose steadily to reach 308 basis points last September. Although the yield spread has narrowed since, it was still 271 basis points in early May of this year. While industrial corporations also suffered to some extent in the general rush of investors into safer securities, the penalty was far smaller than that paid by electric utilities.
— As we look ahead, the demand for funds by electric utilities will remain strong. Despite the current slowdown in construction expenditures, the pace will pick up in 1976 and 1977. This will keep electric utilities heavily dependent on external funds and on the Nation's capital markets. In addition, utilities will have to refinance a heavy volume of low-coupon debt over the next several years. Thus, their interest costs will also rise appreciably.
— For these reasons, among others, electric utilities will need greater — and more speedy — rate relief than most regulatory commissions still seem inclined to grant them. Otherwise, consumers of electric energy — both business firms and households — are the ones who will suffer in the years ahead.

Energy and the Environment: The Tradeoffs for New England

James J. MacKenzie*

I. Introduction

The consumption pattern of energy in the United States, like that of other resources, is determined by many variables. Principal among these are price and convenience. The price of energy has been and continues to be a complicated function of physical availability, international politics, government price regulation, import controls, technological innovation, and environmental regulation, to name but a few of the more important variables.

Contrary to popular belief, however, environmental regulations have never been the primary reason for either the growth or decline of any major source. The consumption of coal, the dirtiest of our fossil fuels, hit its peak, at 77 percent of total energy supply, in 1910. Its relative use has declined since that time because of the availability and convenience of liquid and gaseous fuels — not because of air pollution regulations. Similarly, the consumption of natural gas, the cleanest of our fuels, grew dramatically after World War II because of its convenience and low price, the latter largely the result of Federal price controls.

Recent environmental laws have of course made it more costly to burn dirtier fuels. But within the last five years sulfur oxide scrubbers have been developed to meet EPA emission restrictions. Moreover, a whole range of alternative (if not new) technologies promises to allow the burning of coal essentially without air pollution.

Environmental regulations, therefore, can and will affect the pattern of energy use primarily through the pricing adjustments necessary to produce "clean" energy as measured by the various standards of environmental quality. One of the major goals of the environmental movement is to include within the price of energy all of the social, environmental, and public health costs and risks incurred in its production and consumption. In adopting this essentially economic goal, we environmentalists appear to stand alone. Consumer advocates, energy producers and converters, and politicians continually press for a wide

*Member, Joint Scientific Staff, Massachusetts and National Audubon Societies. He has a Ph.D. in nuclear physics and before joining the Audubon staff in 1970 was a research associate in the Center for Theoretical Physics at the Massachusetts Institute of Technology. He is chairman of the Union of Concerned Scientists, a trustee of the Environmental Defense Fund, and a member of the energy policy committee of the National Sierra Club.

range of subsidies to reduce prices (e.g., through natural gas price regulation), to increase profits (e.g., by continuing depletion allowances and foreign tax credits), or to allow the continued violation of prudent and reasonable environmental safeguards (e.g., those requiring the rehabilitation of strip-mined lands). With the resulting patchwork of subsidies and regulation it is little wonder that the Nation finds itself today faced simultaneously with rampant energy waste in every sector of the economy and a growing gap between supply and demand. Presently, energy prices do not reflect the true and total incremental costs of developing new sources. Consumers are not getting accurate signals about the seriousness of our shortages and the normal brakes of higher prices that should be operating to slow the growth in consumption are absent. Perhaps the clearest example of this unfortunate fact is the severe capital crunch plaguing the electric utilities in the face of continued, albeit reduced, growth in demand.

As an environmentalist I am quite willing to allow an informed and functioning market place (one that is truly competitive) decide which energy sources New England and the Nation will utilize. But in so doing I insist that the price of energy include all of the environmental damages and risks. We are a long way from that situation.

In this paper I review what I believe to be the major risks associated with our energy options. Unfortunately, it is not always possible to quantify these risks. Indeed, in several instances the magnitude of the hazards are subject to ongoing controversy and debate. This is so for several reasons including incomplete research (nuclear safety) and insufficient experience (imported liquefied natural gas, LNG).

In Section II recent trends in New England energy consumption are presented. In Section III the environmental trade-offs among various energy sources available to New England are reviewed. In Section IV some personal views are presented on the direction that I believe we should be taking in planning an environmentally sound energy future.

II. Pattern of New England Energy Consumption

The energy supply picture for New England is substantially different from that of the United States as a whole.

- First, per capita use of energy in New England is only three-fourths of the national average. No doubt this is the result of higher prices here, in turn resulting from our long distance from supplies.
- New England is nearly twice as dependent on oil as the Nation as a whole (85 percent vs. 46 percent of total supply).
- Natural gas plays a relatively minor role in the New England supply picture (9 percent vs. 32 percent for the national average).
- New England electric utilities are heavily dependent on petroleum (60 percent) and nuclear energy (24 percent) as fuels for electricity generation.

These facts are presented in Tables 1 and 2. The trends in New England's energy supply since 1960 are presented in Figure 1.

The most significant changes in New England's supply pattern over the past 15 years include the decline of coal from 13 percent of supply to its present 1.3 percent, and the expansion of oil, natural gas, and nuclear energy by 6, 3, and 3 percentage points (of total energy supply), respectively.

The precipitous decline in the consumption of coal since the mid 1960s is due to the switch by electric utilities to cheap, imported residual oil.[1] This switch is sometimes attributed to environmental regulations, but this is not so. The changeover to oil occurred as soon as import quotas on residual oil were dropped in 1966, long before air pollution regulations required low-sulfur fuel. (See Figure 2.) It was not until 1970, when utilities began to burn lower-sulfur fuel, that coal became once again cheaper than oil.

For our purposes it is important to note that domestic production of New England's two largest sources of energy, petroleum and natural gas, has been dropping steadily over the past few years. It will be difficult to substitute in a massive way for these two fuels in periods short of decades. For the short run, suppliers will have to rely on foreign sources. Discoveries of oil and gas off the Atlantic coast could conceivably reduce our regional need for imports, though not the national need. If the resources of the Atlantic shelf are not substantial, and in the absence of any imaginative political action to utilize new sources of energy, New England will probably continue on a longer basis to import petroleum and natural gas. Since Canada is reducing its exports to us, natural gas will probably be imported in the form of liquefied natural gas (LNG) from North Africa or other sources.

Of course, further reliance on imported oil and gas flies directly in the face of our national policy to reduce dependence on foreign sources. For this reason an effort might be made to fill our growing oil and gas gap with synthetic fuels from coal or via new sources, such as wind and solar energy.

Apparently then, we can expect to have, at least, the following options for direct sources of energy (that is, not including electricity): imports of petroleum from foreign sources or from the outer continental shelf; imports of liquefied natural gas; synthetic fuels from coal; and energy from the sun, including wastes, or from the winds.

In addition to direct sources we must consider the options available to the electric utilities. At the moment New England utilities account for one-fourth of total energy consumption. As indicated in Table 2, 60 percent of our electricity is now generated in oil-fired plants, and 25 percent

[1] In 1965 utilities accounted for 83 percent of New England coal consumption. At that time twice as much electricity was generated by coal as by oil.

Table 1

SOURCES OF ENERGY, 1972

	New England	United States
	Percent	
Petroleum	84.6%	45.7%
Coal	1.3	17.3
Natural Gas	9.1	32.1
Nuclear	3.2	0.8
Hydro	1.8	4.1

Source: "Fuel and Energy Data, United States by States and Regions, 1972", U.S. Department of the Interior, Information Circular 8647.

Table 2

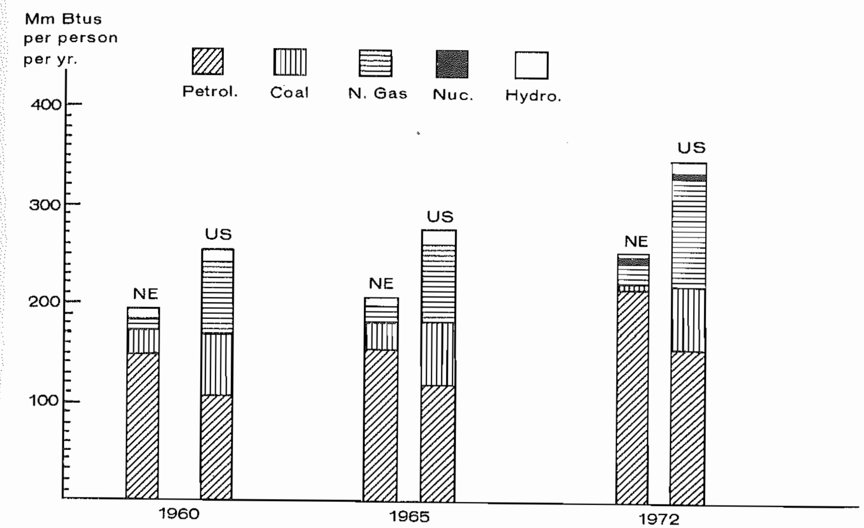
SOURCES OF ELECTRICITY, 1974

	New England	United States
	Percent	
Coal	7.4%	44.4%
Petroleum	60.0	16.0
Natural Gas	1.2	17.1
Nuclear	24.4	6.0
Hydro	6.8	16.1

Source: Federal Power Commission.

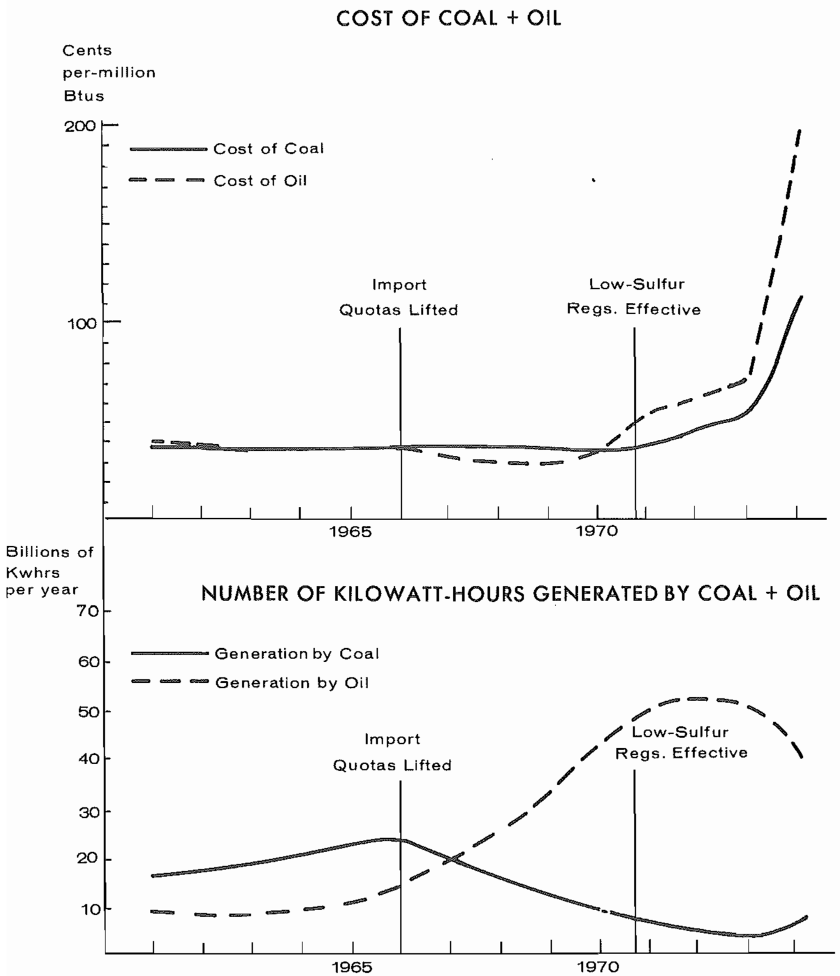
Figure 1

PER CAPITA ENERGY CONSUMPTION
NEW ENGLAND AND THE UNITED STATES
(BY SOURCE)



Source: Bureau of Mines, Fuel and Energy Data: United States by States and Regions, 1972.

Figure 2



Source: Statistical Year Book of the Electric Utility Industry, published by the Edison Electric Institute.

in nuclear plants. In the short term — ten years or less — there are only two energy sources available for electricity production in new plants, coal and nuclear energy. Some time in the 1980s it is possible that wind power could begin to make a contribution. Less certain than wind power would be solar power generated in a "photo thermal" plant. In summary, the options for the utilities are coal and nuclear energy, and perhaps wind and solar power for the longer run.

III. Environmental Trade-offs

Petroleum Impacts

The environmental impact of producing and importing the petroleum needs of New England will fall mostly on the coastal zones and the oceans and will be in the form of oil pollution and land disruption.

Offshore Drilling

Of the remaining domestic oil reserves considered recoverable with present technology, about 40 percent are located in offshore waters. Half of this oil in turn is at water depths of more than 600 feet. The chief hazard of offshore drilling is the danger of a large blowout. After the Santa Barbara blowout many birds were killed and entire plant and animal communities in the intertidal zone were killed by a layer of encrusting oil which was often 1 to 2 centimeters thick.[2] Although recovery from this blowout appeared to be complete less than a year later, no behavioral, physiological, chemical, or biological studies have been performed to confirm this belief.[3]

Other problems occur when the drilling is in shallow coastal waters. These include mechanical, physical, and navigational problems associated with the structures; physical and ecological effects from production activities in unstable marsh lands; and adverse ecological effects from mechanical, hydrological, and physical changes. There is apparently little information on the long-term effects of low level oil pollution. However, documented short-term effects include: 1) the poisoning of marine life filter feeders such as clams, oysters, scallops and mussels; other invertebrates; and fish and marine birds; 2) the disruption of the ecosystem resulting in long-term devastation of marine life from mass destruction of juvenile forms and of food sources of higher species; and 3) the degradation of the environment for human use by reducing economic, recreational, and aesthetic values on both short- and long-term bases.[4]

[2] *The Water's Edge, Critical Problems of the Coastal Zone,* MIT Press, 1972, p. 117.

[3] *Ibid.*

[4] Roger Revelle et al, "Ocean Pollution by Petroleum Hydrocarbons," in *Man's Impact on Terrestrial and Oceanic Ecosystems,* MIT Press, 1971, p. 307.

Tanker Accidents

Petroleum can be imported into New England either in a refined form, as it is now, or as crude oil. Since the United States has a far greater refining capacity than is needed to process domestic oil, the need for more refineries is at least questionable. Nonetheless, if one should be built in New England, it would have to be supplied by large tankers, the accident potential of which is discussed next.

Supertankers have several advantages over a large number of smaller ships. They can be unloaded in areas requiring less shelter than smaller ships. With better trained crews the small losses of oil in port could probably be kept below those of an equivalent number of smaller tankers.

The effects of an accident involving a supertanker are, of course, potentially greater than with a smaller tanker. Supertankers lack maneuverability and require long turning and stopping distances. A 300,000-ton tanker, proceeding at normal speed, would require five miles to come to a stop, while a 16,000-ton tanker requires only half a mile. A collision or grounding of a supertanker, carrying 2 million barrels of oil (330,000 tons), would far overshadow the effects of the Torrey Canyon disaster where 800,000 barrels of oil were lost. Such an accident, leading to a total loss of cargo could add 15 percent to the total amount of petroleum directly entering the oceans in a single year.

Liquefied Natural Gas (LNG)

As the shortage of domestic natural gas deepens, New England gas utilities are turning to foreign sources to supplement declining pipeline supplies. At present, 15 percent of New England's gas supply is supplemental, that is, in the form of LNG, substitute natural gas (identical to natural gas) made from naptha or other feedstock, or propane. In 1972 the National Petroleum Council estimated that by 1985 New England might have to import up to half of its gas supply. In light of our recent experiences with imported oil one must question the wisdom of once again becoming so dependent on foreign sources. It is easy to imagine U.S. companies financing a huge, costly liquefaction, transportation, and storage network only to have the exporting countries arbitrarily and sharply raise prices or even nationalize the holdings.

Our concern here, however, is not with security of supply but with the risks to public health and safety that may arise from importing large amounts of LNG into heavily populated areas. LNG has special properties that make it unique among liquid fuels. First, it must be stored at an extremely low temperature, -260 F. At this temperature natural gas condenses to form a clear, light-weight liquid occupying only 1/630 of the original volume of gas. It is this large reduction in volume that makes shipping gas in the liquid state so attractive.

The major issue of public concern is the possibility of a major accident involving an LNG tank or tanker. In the event of a tanker accident the LNG from a ruptured compartment would spread over the water and

vaporize rapidly to form a large cold cloud of methane. Once vaporized the entire LNG cloud, if ignited, could burn completely within a matter of seconds.

A collision or grounding of an LNG tanker could release 50,000 barrels of LNG, a typical volume of the cargo hold of such a vessel. If ignited shortly after spilling, this volume of fuel would give persons radiation burns from the heat up to 2.5 miles from the spill. If the LNG ignited later, after vaporizing, it would burn as a giant fireball which would rise to over a mile in the air and burn persons up to five miles from the spill. A small spill, say, 30,000 gallons, which is about the volume of a tank car, would burn persons up to a half-mile from the accident. These fires would be extremely difficult to extinguish and could in fact burn to completion before firefighters could even arrive at the scene.

Although high quality control is exercised in the construction of LNG tanks and tankers, the same statement can be made relative to almost any costly industrial activity. The sad fact remains that totally unexpected accidents can and do occur. The most prudent safeguard to protect the public from serious LNG fires is the remote siting of the storage tanks. Storage facilities for LNG near population centers should be minimized. (There are, alas, already over 1.5 million barrels of LNG storage capability in the Boston Harbor area alone.) Transport of large quantities by truck or rail should be avoided. Transportation of small quantities by truck would be reasonable provided the route and time of transport are carefully chosen to avoid risks to large numbers of people.

Low Heating Value Gas from Coal

As we have indicated in Table 1, New England is dependent on oil and natural gas for 94 percent of its energy supply. These two fuels are likely to grow ever more expensive as domestic oil production drops further, as the oil-exporting nations continue to raise their prices, and as the price of natural gas rises because of both its (likely) deregulation and the high cost of producing new supplies (OCS gas, LNG, and substitute natural gas — SNG). For these reasons increased attention is being given to developing cleaner methods of burning coal whose domestically recoverable resources are almost 20 times those of oil and natural gas taken together.

The environmental and safety problems posed by the use of coal are, of course, legendary. Its history is one of extraordinary risks for its workers, acid mine drainage destroying streams and soil, burning refuse banks, subsidence beneath worked-out mines, unreclaimed strip mines, and lastly, sulfur and particulate air pollution that has shortened the lives of countless Americans living in heavily populated areas.

Fortunately, and largely as the result of the environmental movement of the past decade, the problems that have characterized its past are now being seriously addressed for the first time. Since passage of the Federal Coal Mine Health and Safety Act of 1969 the risks to underground coal miners have been reduced and are now comparable with those faced by other underground miners. For between pennies per ton (in the west) and perhaps a dollar per ton (in the east) strip-mined lands can be rehabilitated. Long-wall mining techniques are now being tested in this country that can effectively deal with the problems of subsidence. And a host of technologies, some new, some old, are being developed and analyzed and promise to allow the consumption of coal with virtually no air pollution at all.

Several of these processes are now commercially available and could be utilized by New England consumers, particularly industry, to supply clean, secure fuel at prices competitive with oil. Table 3 lists the energy sources for New England industry. More than 75 percent of this sector's (direct) energy is derived from oil and natural gas: As the curtailment of natural gas grows, industry will be forced to switch to oil or other sources; gasified coal offers a viable alternative.

Coal can be converted into a low heating value gas (100-300 Btus per cubic foot), or, with additional cost and effort, into methane (1000 Btus per cubic foot), which is the same as natural gas. For industrial purposes the lower cost, low-Btu fuel is quite adequate.

For small scale industrial users (equivalent to less than 100 barrels of oil per day) many proven gasifiers could be in operation in New England within two to three years if the coal could be made available. These could meet the needs of industrial parks as well as manufacturers of brick, glass, ceramics, baked goods, and the like.[5] These "producers" use air and could burn low-sulfur anthracite. These units would be ideal if the coal reserves on the Narragansett basin prove to be commercially and environmentally exploitable. The resulting "power gas," mostly hydrogen, carbon monoxide, carbon dioxide, and nitrogen, could easily be cleaned of its ash and would meet environmental standards.

Larger gasifiers, using oxygen, that will accept any kind of coal no matter how dirty, are also available. The Koppers-Totzek unit, marketed for more than two decades by the Koppers Company, Inc. of Pittsburgh, can burn as little as 400 tons per day (equivalent to 1800 barrels of oil), to produce 300 Btu gas, free of sulfur and ash. The unit costs for the gas are lower for large installations. For the largest New England industries (paper mills with oil consumption on the order of 3500 barrels per day) the gas would cost about $2.50 per million Btus, using $25 per ton coal.[6] This is only slightly more than oil at $13 per barrel. Obviously, import tariffs and oil price rises could easily tip the balance in favor of coal.

Lurgi gasifiers using air rather than oxygen are also available to supply clean gas from coal. These units have the advantage of producing gas

[5] Arthur M. Squires, "Coal: A Past and Future King," in *Ambio 3*, No. 1, 1974. "Clean Fuels from Coal Gasification," *Science 184*, April 19, 1974.

[6] "Coal Gasification: Neglected Response to America's Energy Needs," Koppers Co., Inc., March 1975.

Table 3

ENERGY SOURCES FOR NEW ENGLAND INDUSTRY, 1972

	Percent
Petroleum	55.9%
Electricity	22.2
Natural Gas	20.3
Coal	1.4

Source: Department of the Interior.

under pressure suitable for generating electricity by utilities in gas turbines, or better, in highly efficient combined cycle power plants in which the exhaust from the turbines is used to raise steam for a conventional steam turbine.

Fluidized bed gasifiers of French design are also available commercially to convert coal into a low heating value gas. In these gasifiers the coal is burned while suspended in an upward-directed stream of air. These units are even more efficient and cleaner than the Lurgi and Koppers designs. They can also be scaled up more easily to supply a pollution-free fuel for electric utilities.

Although gasifiers to make clean power gas are commercially available, none has yet been built in the United States. The basic reason is uncertainty over national energy policy. Companies are justly concerned that if they construct gasification plants their investments may be jeopardized through arbitrary decreases in the price of imported oil. Similarly a company opting for relatively more expensive gasified coal would be at a competitive disadvantage if others were still able to obtain cheap regulated natural gas. The Congress by continuing the present unwieldy system of gas regulation and by failing to deal with the problem of imports is simultaneously discouraging conservation, the exploration for more domestic gas, and the use of somewhat more expensive but more secure energy sources such as coal and solar energy.

SNG and Synthetic Oil from Coal

Besides being converted into low-Btu gas, coal can also be converted into methane (Substitute Natural Gas). The production of SNG from coal is a much more difficult and expensive task than producing power gas. Consequently, it may well be ultimately easier and cheaper to convert industry and the electric utilities to low-Btu gas and to divert the natural gas saved (65 percent of all natural gas) to residential and commercial sectors.

At least seven commercial processes are being developed domestically to produce methane from coal. Two of these are in the pilot-plant stage and are apparently experiencing some engineering problems. The El Paso Natural Gas Company plans to build a gasification plant in New Mexico utilizing cheap, low-grade coal and Lurgi gasifiers followed by clean-up and methanation. This particular process has been demonstrated to be technically feasible through tests in Westfield, Scotland using U.S. coals. The El Paso plant will probably cost over $300 million to build (1974 dollars), will produce 250 million cubic feet per day of gas, about 1/2 percent of U.S. demand, at a cost of about $2 per million Btus at the plant, about four times the cost of regulated domestic gas at the wellhead.

Many difficult engineering problems still have to be faced before large-scale coal conversion plants begin producing methane. Structural problems, corrosion and agglomeration problems, and problems with introducing coal continuously into the vessel without losing pressure, all remain to be satisfactorily solved. Commercial-sized coal-gasification plants using any of the new processes would seem to be still a decade or more away.

The commercial liquefaction of coal in New England or anywhere else appears to be yet a step further away than SNG production. A number of processes, all expected to be expensive, have been developed on a small scale but pilot plants and full-scale commercial plants have yet to be built. Such plants will probably not make any important contribution before the late 1980s.

Solar Energy

Energy from the sun can be captured in a variety of ways ranging from the heating of flat-plate collectors to the growing and harvesting of algae in ponds. Some applications are nearly commercial, such as the heating and cooling of buildings; some, including wind power, need large-scale demonstrations to test potential commercial designs; still other applications — large-scale electricity generation either on earth or in a synchronous orbit in space — need a great deal more research and development.

The environmental, social, and institutional impacts of using solar energy obviously depend on the particular technology employed. Those effects accompanying the heating and cooling of buildings are receiving the most attention while potential impacts of less developed systems are still only elements in large-impact matrices.

The economic feasibility of using solar energy is similarly very much dependent on the process and on geographic location. The location is important because of regional variation in both the amount of sunlight received and the costs of competing energy sources.

Heating and Cooling of Buildings

Without question the most nearly commercial application of solar energy is for water heating and the heating and cooling of buildings. In every part of the country solar-assisted homes and commercial buildings are now being constructed.[7] In most of these buildings part or all of the conventional roofs are replaced by collectors through which air or water is circulated and heated. The collectors themselves are usually just flat aluminum or steel sheets painted black, covered with glass to prevent heat losses, and insulated on the back to prevent excessive heating of the building's highest floor. The air or water passes through insulated ducts or pipes to a storage system usually in the basement and containing crushed stones or just water. Enough heat can be stored on a sunny winter day to carry the building through two or three consecutive cloudy days. For longer sunless periods an auxiliary heating system would supply the extra needed energy.

Used in this way solar energy will add 10 to 15 percent to the initial cost of the building. Because of the expense, buildings to be heated with the sun should be well designed and well insulated. Double or even triple glazing, well-insulated walls and floors, and "passive" collective systems such as large thermopane windows facing south, should all be considered in the design of a solar-assisted building (or for any other building, for that matter).

The Energy Research and Development Administration (ERDA) has estimated that by 1985 the United States could have 600,000 new solar homes, 55,000 new solar commercial buildings, and 13,000 commercial retrofits.[8] The combined annual fuel savings in 1985 would be about 36 million barrels of oil. One study performed for the National Science Foundation concluded that two-thirds of the 60,000,000 buildings to be constructed in the United States in the next 25 years are viable, cost-effective candidates for solar-energy systems. If all of these buildings were in fact solar-equipped, the annual electrical savings (assuming solar energy would be competing with electric heating) would amount to 1,500 billion kilowatt-hours, the total electrical output of the United States in 1970.[9]

The principal environmental effects of using solar collectors include the reduced need for conventional fuels, the consequent reduction in land use and pollution associated with conventional energy production, and the increased consumption of materials needed to produce the collectors and components. Since collector systems would be constructed of common

[7]William A. Shurcliff, *Solar Heated Buildings, A Brief Survey,* 1975. Available for $7, postpaid, from W. A. Shurcliff, 19 Appleton Street, Cambridge, MA 02138.

[8]"National Plans for Solar Heating and Cooling," ERDA-23, March 1975.

[9]Reported in "Solar Energy for Earth," American Institute of Aeronautics and Astronautics, New York, 1975, page 24.

building materials such as steel, aluminum, glass, insulation, concrete, pipes, etc., the direct environmental impact of their manufacture would be similar to those of the general construction industry. The energy payback time for these systems is typically two years or less.

In addition to these environmental effects there will be legal and institutional problems to deal with. The definition and determination of "sun rights" associated with property will have to be settled. Building and zoning codes will have to be examined to be sure that they do not inadvertently preclude the use of solar-space conditioning. Local property taxes, if applied to the added cost of solar heating systems, could reduce the effective fuel savings and remove the incentive for installing them.

Because of our dependence on oil we in New England are vulnerable to both embargoes and escalating fuel prices. Solar technology for heating and cooling offers an environmentally clean, essentially inflation-proof alternative to continued dependence on outside sources of energy. In addition it offers economic development opportunities for our sagging economy. Innovative engineering, system design and analysis, and light manufacturing and assembly are the key ingredients for a successful solar economy. They also characterize the best qualities of our regional economy. Federal funds will be increasing to help accelerate the process of commercialization. I fervently hope that we will have the wisdom and foresight to move aggressively and take advantage of the many opportunities that this new source of energy affords.

Wind Power

The use of winds to provide useful power is as old as history itself. In western Europe tens of thousands of windmills have been used since the Middle Ages to grind grain, pump water, and saw lumber. Windmills to generate electricity date back to 1895. By 1910 windmills in Denmark were supplying the equivalent of 200 megawatts of electrical power. During both world wars Denmark relied heavily on windmills for its electricity. During the 1940s the world's largest wind generator, the Smith-Putnam machine with a generating capacity of 1.25 megawatts, operated successfully in Vermont. In 1945 because of war-time limitations a known structural defect that had developed in one of the blades could not be repaired and the blade failed on March 26. By any standard, however, the experiment was a success, and a more efficient, less costly model was proposed for full commercial operation. Unfortunately further funds were lacking and the project died.

Interest in the United States in power from the winds has renewed because of our energy shortages. In 1975 NASA began testing a 100 kilowatt machine at Sandusky, Ohio. From the experience gained with this machine three large commercial units will be designed and installed in various parts of the country with construction beginning in 1976. Design of a one-megawatt machine will also begin in 1976. By the late 1970s large

wind generators in the one-megawatt range should be available for commercial operation. Additional research is being undertaken into various methods of storing the energy using flywheels, hydrogen storage, and compressed air. Further study is also needed on possible environmental impacts such as the effects of large numbers of windmills on local weather, bird population, and perhaps radio communications.

New England is fortunate in that it has a vast potential for using the winds as a source of power. The most productive sites are located on the continental shelf, followed by sites in the White Mountains. Professor William E. Heronemus of the University of Massachusetts has made a very detailed engineering and economic analysis of the feasibility of an ocean-based wind power system for New England.[10] Heronemus has designed a system to supply New England with 160 billion kilowatt-hours of electricity per year, almost 2 1/2 times its entire 1973 demand. Using proven marine techniques and commercial equipment for the electrolyzers (to make hydrogen from sea water) and fuel cells (to convert the hydrogen back to electricity when needed) he would deploy 83 floating generating units, each unit containing 165 wind stations, for a total of 14,000 wind stations. Each station would consist of three 200-foot-diameter, 2-megawatt generators mounted on a floating platform which would be anchored to the ocean floor. The generators would make electricity to electrolyze water into hydrogen and oxygen. The hydrogen would be stored in underwater chambers to be pumped ashore and converted into electricity on demand. The entire system would cost an estimated $22 billion to build. He calculates that a kilowatt-hour of electricity would be available, on shore, for less than 2.5 cents (1972 dollars).

Admittedly this system is not going to be built, full blown, within the next few years. Heronemus would have it constructed in phases and completed by 1990 to meet all of the new growth between now and then. The careful engineering and economic analysis that he has put into it and the relatively low costs that he foresees for the generated power clearly indicate that more detailed feasibility studies are warranted. Included in these would be an examination of possible effects on marine navigation and offshore fisheries.

Solid Waste

The burnable fraction of solid waste is composed mostly of paper and is therefore considered to be an indirect form of solar energy. During 1971 the United States generated about 880 million tons of dry, organic wastes. About 15 percent of this material, 136 million tons, was in the form of urban wastes and was readily collectable. It could have been used

[10] Heronemus is a naval architect and marine engineer with 27 years of practical design and engineering experience in the U.S. Navy.

for its energy value rather than being buried or burned without heat recovery. It is estimated that the combustible portion of this refuse (40 percent of refuse is water or nonburnables) had a heat value of 1,400 trillion Btus, or about 2 percent of total national energy consumption. If these wastes had been used to generate electricity they could have produced about 9 percent of all the electricity generated in the United States in 1970.

Three processes are now being developed to recover energy from solid wastes. The first shreds and then burns the trash in an incinerator or boiler to produce process steam or electricity. In the other two processes the trash is treated in a large vessel and converted into oil, or into a combination of oil, char, and low heating-value gas.

According to the EPA about 50 percent of urban refuse (by weight) is paper, and if burned would account for 70 percent of the total energy recovered from solid waste. In New England about 76 percent of the population (9.2 million in 1973) lives in urban areas. At five pounds of solid waste per person per day, about 8.4 million tons of waste are generated annually. (This figure includes moisture and non-combustible objects.) The heat content of this waste is about 84 trillion Btus, equivalent to 15 million barrels of residual oil, or about 9 percent of all the residual oil consumed in New England in 1973. If the trash had been burned to generate electricity, it would have met about 12 percent of New England's 1973 electricity demands.

Burning solid waste in a modern resource recovery plant has many environmental advantages. A new plant would be equipped with scrubbers adequate to meet EPA emission requirements. Moreover, the size of the investment would justify hiring a professional staff to ensure proper operation and maintenance of the facility. A large plant could serve many communities and thereby eliminate the need for individual dumps and landfills. The reclamation of metals in addition to energy would be another step in the direction of reducing demands for virgin raw materials. While the burning of solid waste is not the complete answer to New England's energy problems, it obviously can make a significant conbribution to it.

Electric Power Production

The trend in New England and in the United States has been toward an increasing dependence on electricity as a source of energy. In 1960 electric power generation accounted for 16.6 percent of total New England energy consumption; by 1972 this figure had reached 24.3 percent. Several reasons explain this gradual shift. First and most important is the low cost of installing electric heat. Speculative builders of residential and commercial buildings are usually undercapitalized and make every effort to lower first costs, even at the expense of higher operating costs. The growth in the use of heavy electric appliances such as freezers, washers, dryers, and air conditioners accounts for much of the remaining growth.

Fuel Options

In the mid 1960s the east coast utilities made a major shift from coal to imported oil as a source of electricity. This change was dictated by the momentary economic advantage of oil over coal; in retrospect it was a mistake. The utilities would be far better off now if they had sponsored the research necessary to burn coal cleanly and obtained long-term contracts with domestic coal producers. As things stand today, oil is no longer a reliable or economic fuel and no electric company would consider constructing a new oil-fired power plant.

For the near term only two fuel options are really available for new generating plants, coal and nuclear energy; neither is an environmental bargain. The problems with these sources, however, are not inherent in the fuels. Rather they reflect a chronic political failure (in the broadest sense) to commit the funds and resources necessary to allow their clean and safe utilization.

Electricity from Coal

Coal resources in the United States are enormous. Present annual production is about .6 billion tons compared with proven reserves of 433 billion tons. One-third of these reserves are low in sulfur, less than 1 percent. Total remaining recoverable coal resources are estimated at 1,600 billion tons. At present consumption rates we have more than 700 years supply from proven reserves alone.

Many public health and environmental problems are associated with the use of coal. They range from the safety risks experienced by coal miners to the acid sulfate air pollution affecting the eastern third of the Nation. Fortunately, most of the ill effects from coal use are preventable. Most lands that are being strip mined can be rehabilitated to productive uses without severe economic penalty. According to recent studies sponsored by the Department of Interior, reclamation costs range between $.12 per ton in the west to $1.37 per ton in the east.[11] These costs represent, at most, a small percentage increase in the final delivered cost of coal and should rightly be borne by consumers. Similarly, underground mines have been made considerably safer over the past five years, albeit at a loss of productivity, especially in older mines.

Air pollution is probably the most serious environmental impact of burning coal. Sulfur dioxide and particulates are presently the two principal pollutants of direct public health concern. Recent studies, however, performed by EPA suggest that the sulfates into which sulfur dioxide is converted may be a more serious health hazard than the sulfur dioxide.

[11] "Impact of Higher Ecological Costs on Surface Mining," NTIS No. PB 240 441AS, July 1975.

Fuel Gas Desulfurization

Since the late 1960s a great deal of time and money has been spent in developing flue gas desulfurization (FGD) technology. FGD systems, or "scrubbers" as they are frequently called, remove the sulfur oxide pollutants before they enter the chimney. According to the Environmental Protection Agency, a number of scrubbers are now commercially available and "...can be used continuously, reliably and effectively to control sulfur oxide emissions from power plants..."[12] Many of these units have shown higher than a 90 percent reliability for periods of five to eight months of boiler operation. Recently one major manufacturer announced the successful 12-month operation of a scrubber with a 90 percent reliability and a 90 percent sulfur oxide removal efficiency.[13]

With the successful demonstration of FGD technology users of large amounts of coal will now have available to them the means for burning high sulfur coal in new installations while still meeting EPA emission standards. In addition, in many instances FGD systems can be retrofitted to existing boilers.

While FGD technology capable of reducing sulfur emissions by 90 percent offers an immediate means to reduce pollutant emissions, it may not be adequate on a long-term basis to achieve air quality standards if the use of coal increases substantially. Also, FGD systems do not remove the sub-micron sized particles of ash that seem to pose the most serious health hazard because of their ability to penetrate deeply into the lungs. For these reasons FGD technology is generally viewed as an intermediate means for burning coal, but not the ultimate answer. For this, coal will have to be either thoroughly cleaned before combustion or else converted into a clean liquid or gaseous fuel.

Low Btu Gas

As we mentioned in an earlier discussion on coal, gasifiers are now available that can be used to supply clean gas from coal for either existing fossil-fuel plants or for new combined-cycle units. For the proven Koppers-Totzek unit, for example, we can state the following:[14]

- Sulfur emissions would be less than those from burning 0.1 percent sulfur oil;
- The entire gasification system can be started up within 30 minutes from a hot-standby mode;

[12]"EPA Releases Scrubber Reports," EPA News Release, September 25, 1974.

[13]"Stack Gas Scrubber Makes the Grade," *Chemical and Engineering News,* January 27, 1975.

[14]"Utility Gas by the K-T Process," Koppers Co., Inc., 1974.

- Little equipment change would be required on existing boilers;
- A very high conversion efficiency of 79 percent is achieved between eastern coal and the resulting (cold) gas.

The capital costs for installing such a system on a large 1,000 megawatt power plant would be about $120 per kilowatt. These charges on a new plant might be more than offset, however, by the elimination of both the precipitator and sulfur scrubber system.

Solvent Refined Coal

Gasified coal presents an attractive, clean option for New England utilities. The process would be particularly suited for a new power plant that could utilize both gas and steam cycles. For older, coal-fired plants the solvent refining of coal offers another environmentally attractive possibility.

Solvent refining is a method of treating coal which leads to a heavy liquid or a low-melting organic solid, suitable for burning in present coal plants. The coal is first dissolved in a coal-derived solvent. The solution is then filtered to remove the ash and other insoluble materials. The final product has a very high heating value (16,000 Btus per pound), less than 0.1 percent ash, and very little sulfur. A pilot solvent refining plant will soon be in operation in Tacoma, Washington.

Nuclear Energy

Without too much doubt nuclear power is the first choice of New England utilities for new base-loaded capacity. The New England Power Planning Organization, as of October 1, 1974, projects that 41 percent of New England's electrical capacity will be nuclear by 1984.

Nuclear power has several attractive features. Most important is its lack of air pollution. Anyone who has wrestled with the sulfur and particulate problems of the Northeast will appreciate this feature. Nuclear power plants also emit no carbon dioxide. There is evidence to suggest that the build-up of this gas in the atmosphere from burning fossil fuels may trigger a global warming trend with deleterious effects on the climate. According to some calculations this trend could begin at almost any time and once started would be difficult or impossible to reverse. A conservative approach to this problem would be to emit as little carbon dioxide as possible; that is, to burn as few fossil fuels as we can.[15]

Nuclear plants do emit small amounts of radioactivity to the environment but so far these emissions have caused no perceptible harm. This situation could change through a gradual build-up of radioactivity,

[15]We note that the virtue of no sulfates, particulates, or carbon dioxide is also shared by solar and wind energy. These latter sources have the additional benefit of not adding to the total heat load of the earth.

such as from the radioactive gas krypton-85, if and as more and more reactors are built. However for relatively modest sums of money no radioactivity at all need be released from them.

Supplying uranium for nuclear power plants (and weapons) has caused environmental problems in much the same fashion as coal mining has. Underground miners have suffered from silicosis and from excessive lung cancer. Several of the rivers of the Southwest have been polluted with radium from uranium mills. And thousands of homes and schools were built on radioactive mill tailings in the Southwest because of negligence on the part of the AEC.

Future uranium mining also promises to be as environmentally destructive as coal mining. At present all known and speculative high-grade uranium reserves (2.5 million tons) are sufficient to last for only two decades or so. Without a successful, economic breeder supplying a substitute fuel (plutonium), uranium will have to be obtained from low-grade ores by the 1990s. This implies the same kind of destructive large-scale strip mining and rock crushing that we associate with coal mining and oil shales. And at present the breeder program is in serious trouble because of escalating costs and design problems related to safety and breeding efficiency.

The current switch by utilities from oil to nuclear power is disturbingly reminiscent of their switch ten years ago from coal to oil. The fuel economics look favorable, provided that one does not look too far into the future.

More serious, though, than fuel availability are the problems of accidents, plant security, international terrorism, and waste storage. In my view controlling power plant accidents is the most immediate and pressing problem faced by reactors. Nuclear power plants generate large amounts of radioactivity as they "burn" uranium during day-to-day operations. This radioactivity normally stays almost entirely within the thousands of 12-foot-long fuel rods that comprise the core assembly. The core in turn heats (and is simultaneously cooled by) the water passing up through it, generating steam from which electricity is made.

If a large pipe in a reactor's cooling system should rupture, the normal cooling water would be quickly lost from the reactor vessel (a Loss of Coolant Accident — LOCA). If emergency cooling water is not supplied within a minute from the Emergency Core Cooling System (ECCS), the heat in the hot radioactive core will begin to melt the fuel. The fuel will melt first through the reactor vessel and then through the concrete below. Large amounts of radioactivity could escape into the environment and under the worst circumstances there could be lethal effects for tens of miles from the power plant and land denial, because of radioactive contamination, over tens of thousands of square miles.

The ECCS now installed in reactors have never been tested under accident conditions. Instead, elaborate computer codes have been developed and relied upon to predict their performance during accidents. According to a recent review of reactor safety by the AEC,

> . . .the current generation of industry and AEC calculational codes are not able to describe the detailed behavior of the injected water from first principle considerations, and the applicable confirmatory experimental work has not been completed.[16]

Indeed, most of the work lies in the future, including crucial work bearing on ECCS performance. The most important experimental program, the Loss of Fluid Test (LOFT), is almost a decade behind schedule and will not be able to supply useful information on ECCS behavior for at least a few more years.

We thus find ourselves in the position of having the performance of crucial safety systems in $100 billion worth of power plants still uncertain.

The probability of having major accidents which would require the ECCS is also uncertain. The AEC sponsored a major study (the so-called "Rasmussen Study" after its director Dr. Norman Rasmussen of MIT) to estimate the likelihood of a major accident. However, the computer methods used here are also of questionable reliability. The basic criticism is that nuclear power plants are so complex that one cannot think of, and therefore model, all of the important ways in which they can get into trouble. Estimates of probabilities of accidents will of necessity be too optimistic, that is, too low. In a lengthy review of the AEC study the American Physical Society (APS), the professional society of physicists, concluded that they (APS authors) did "...not now have confidence in the presently calculated absolute values of the probabilities..." of accidents, as estimated in the AEC study. The APS study also concluded that "...no comprehensive thoroughly *quantitative* basis now exists for evaluating ECCS performance, because of inadequacies in the present data base and calculational codes."

Reactor meltdowns need not result solely from accidents. They could be caused deliberately by saboteurs from either within or from outside. Sabotage against utilities has become more frequent during the past few years, particularly on the west coast where substations and transmission lines have been blown up. Nuclear power plant security is now inadequate to deal with these threats. It seems certain that as few as three or four well-trained commandos, of the sort trained in great numbers by our own military forces, could take over most reactors and using shaped charges or other means cause incalculable damage. The whole security problem is just beginning to receive the attention it deserves.

More global problems are presented by the increasing availability of plutonium, an extremely toxic waste product of all reactor operations. As the use of nuclear power plants spreads so will the technology for processing and storing the spent fuel. Plutonium, a valuable by-product of

[16]"The Safety of Nuclear Power Reactors and Related Facilities," WASH-1250, Final Draft, July 1973, pp. 7-15.

these operations can be used either to fuel reactors or to create nuclear weapons. One can imagine international terrorist groups hijacking shipments of plutonium and using the material to extort huge ransoms under the threat of either destruction from a crude bomb or an attack on civilian populations using radiological weapons. How could an industrialized nation resist such a threat? Indeed, it may already be too late to avoid the prospect of nuclear blackmail. The United States is only one of many suppliers of nuclear technology. And the know-how to construct nuclear bombs can be found in numerous unclassified documents.

The permanent storage of nuclear wastes away from the environment is a problem that should have at least one good technical solution. Unfortunately waste storage has not received the care and attention that it deserves. Numerous leaks of radioactive wastes have occurred from storage tanks in the state of Washington and the only permanent waste disposal site chosen by the AEC, in Lyons, Kansas, turned out in the end to be totally unsuitable. The AEC had simply not done its homework. As with safety, the symptoms of the waste problem are technological, but the real problem is one of poor management. We can only hope that no further large releases of radioactive wastes will occur before a permanent storage site is selected and the materials are solidified and buried.

IV. New England's Energy Future — A Personal View

The response so far of the New England states to the energy crisis has been disappointing. The first tendency among government leaders seems to be to assume a grand conspiracy and to deal with the problem on that basis. Thus we hear unsubstantiated claims that vast quantities of domestic oil and natural gas are being withheld from market until prices rise even more. Or that the electric utilities are somehow gouging their customers through the fuel adjustment clause. Unfortunately the problem is not that simple. The underlying fact that we all must face is that domestic oil and gas supplies will continue to decrease and that long-term substitutes will have to be found and used, and the sooner the better. We have reviewed in this paper the major options that we in New England have available. Coal is plentiful and could be used, after gasification or refining, by both industry and utilities. It offers the possibility of long-term contracts and price stability. But if the carbon dioxide problem worsens over the next few decades, the use of coal and other fossil fuels may have to be reduced.

Nuclear energy likewise is an option and is in fact the preferred one among the utilities. It presupposes, nonetheless, the solution of many outstanding problems and the successful development of a safe and economical breeder reactor. Alvin Weinberg, the former director of Oak Ridge National Laboratory, has described the acceptance of nuclear power as the acceptance of a Faustian bargain. For its great benefits we must forever exercise extreme care and diligence. To prevent the possibility of serious accidents all nuclear power plants must be built with the

highest possible degree of quality control; security procedures around power plants must be tight; international terrorism must be effectively curtailed; and high-level wastes must be guarded for at least a thousand years after burial. Having been deeply involved in the nuclear controversy for the past six years I (and many others) have concluded that the requirements of a nuclear economy are too much for us, at least for now. Just on the safety issue alone we have experienced ignorance and insensitivity among regulators, continued suppression of adverse experimental data, the truncation of important safety research programs, and poor quality control in the construction of power plants.

Solar energy, in its various forms, offers a future free of almost all of these problems. Today it can be used to heat and cool buildings, and to generate electricity from the winds. It creates no radioactivity and no air pollution. In my view New England should begin a major program to introduce this source of energy. We should be building solar-assisted buildings and gaining experience with wind generators both large and small.

Solar energy is obviously not the complete or immediate solution to all of our problems. As an interim means for generating electricity I would prefer gasified coal to nuclear energy. The unsolved problems presented by the latter source are too many and too serious to make further commitments at this time. Within five to ten years it is possible that many of these problems could be solved. A continuing assessment is warranted.

In this paper we have focused on energy supply. A final observation on demand management seems to be in order. Conservation — the optimal use of resources — and accurate energy pricing, without subsidies, should be the cornerstones of New England and national energy policy irrespective of our energy choices. A vigorous program of consumer education in every sector of the economy is long overdue, as is an overhaul of our complete energy pricing system from natural gas regulation to electric rate structures.

Discussion

Peter Judd*

I want to take issue with the premise, which is stated at the beginning, that the price of energy should incorporate all of the associated social, environmental, and public health costs and risks. It sounds good but it abates the major question. The environmental cost depends on three things. 1) What is being done? In some cases this can be quantified and in some cases, such as the solar reflectors in the city or a windmill on the White Mountains, it cannot. 2) Judgment as to its effect, whether it is good or bad. This depends upon information, some of which can be quantified and some of which cannot. Often the information is disputed and experts disagree. An example is the question of nuclear power. 3) What does it cost to mitigate the problem? This raises the problem of trade-offs.

Let us consider some examples of environmental costs in which the questions of judgment about what is being done, how bad it is and what the costs of mitigating the problems are all raised in various forms. For example, the So2 controversy is one in which scientists and public health experts still disagree about the effects on health. Now it appears that there may be new hazards, such as sulfur acids, which are considered to be even more severe. However, our society has already made the decision that So2 is injurious to human health and now the question is how much control is to be exercised on the burning of So2. Various states have different answers to that, beginning at .5 percent sulfur for fuel burned in the power plants and home heating installations in Connecticut. Now that matter affects human health and is rather grave. Many of the water pollution environmental costs do not affect human health, for example, as the objective of having swimming pool water in, say, the lower Delaware Bay by the year 1985. This costs a great deal of money and the money could be spent elsewhere to provide swimming facilities. There is no access to the water anyway since it is an industrial area. Is the cleaning up of that particular area an environmental cost? Cooling towers for some power plants are also examples of environmental costs about which one can have serious reservations. There is a cooling tower in Connecticut which runs all year round although it really need run only 10-12 weeks in the summer.

*Consultant and writer on environmental affairs. At present he works primarily for the Northeast Utilities Service Company in Hartford.

Yet the year-round operation is considered an environmental cost. Finally, let me give two examples of environmental cost which are going to be accepted in New England and which involve large sums of money about which I think there could be considerable disagreement. In one case a fish ladder is to be built to bring salmon, of which one has appeared, up the Connecticut River at a cost in excess of $10 million. No study has been done of who is going to benefit from this and of the relationship between the benefits and costs. In another case $10 million of capital, which we learned yesterday is scarce, is going to be spent on the Connecticut River to place two 245 KD transmission line crossings, which have been in place since 1966, underground for one mile. These crossings are located on land the utility gave to the state park. Are these all environmental costs? One must decide what an environmental cost is and what the value of mitigating it is.

Now in our society these questions are decided not by systematic analysis but by the push and pull of interest-group politics. Sometimes that turns out to be extremely beneficial. However, at this time of scarcity we face very serious conflicts some of which are mentioned in Jim MacKenzie's paper. The question of determining the environmental cost is really what this is all about. However, the paper also appears to endorse the goal of reducing the region's reliance on the fossil fuels, gas and oil. It says so in words, not in numbers. It says that for the next ten years new plants for electric generation must be coal or nuclear and that we must continue our dependence on imported oil for the foreseeable future as well. It also presents a cornucopia of possibilities, technological possibilities, which have as their basis the additional goal of providing a flexible supply.

Thus I would propose that we add to the environmental objective: first, the two objectives of reducing dependence and increasing diversity, and secondly, the use of technology of proven reliability. These two add very important constraints to what this paper has proposed. They limit our ability to place major reliance, for example, on coal, a major implication of this paper. In principle coal could take over much of what the utilities have planned to be nuclear. We're talking about eastern high-sulfur coal, about a delapidated railroad system, about scrubbers, and I think the paper is very optimistic about the use of scrubbers. I think that it is going to be very unfortunate for New England if we have to install scrubbers. In Connecticut it costs as much or more to put scrubbers on some of the old plants than the plants' depreciated value. We have to remember that when we are talking about additions to capacity we are speaking of very large plants but at present the scrubbers that have partially worked out in the West, in the Mid-west and Philadelphia are not on the size plants that we are discussing.

The technology for coal, removal of gases, fluidized lead combustion and various new techniques of burning coal, will not be developed in New England but by utilities in the Middle West and the Far West that use great quantities of coal. I don't think that there is any prospect of our utilities taking the lead in developing coal technologies; I think we must follow. At the moment the $25 ton coal that is referred to in the paper is not available and we should not minimize the problems of ash disposal. Ash was disposed of for many years by utilities in this region but the region has grown up a great deal since then.

Now the solar technologies may also be given too much emphasis here, although they have a very important role to play. I think MacKenzie is correct in emphasizing the direct use potential for space conditioning and its environmental benefits. The economics, of course, are a real problem. There is no sign whatsoever in my state that people as a matter of course are installing solar systems because of higher oil or electricity costs. They simply aren't doing it. There are some experiments but the builders, who build most houses, aren't doing it and further the houses are not sited to the south as they should be. So if we are to have a large number of houses heated in part by the sun by the year 1985, we haven't even begun on it. I myself believe that solar heat will become economically attractive along with bulk peak rates and storage systems for electricity and that it's in keeping with certain economic and financial objectives for utilities to offer these rates. Consequently, I think that by the 1980s we are going to see solar use supplementing electricity for direct heating, perhaps for cooling as well.

The wind example in the paper, Professor Heronemus's grand design of 16,000 windmills on Georges Bank, has been given a great play, and again I find this internally inconsistent with criticisms of utilities for plans made in the past that don't bear out in the future. Here is a great plan for supplying all of New England's power from Georges Bank which would be extremely vulnerable to interruption by weather or by hostile means. I think we're not talking about a real possibility except for supplementary use, perhaps in the distribution system and perhaps to supplement some residences or industrial plants.

In solid waste, again a great plan is made for something like 13 percent of the region's energy supply to come from this source. But to put this in perspective, there's a plant in Bridgeport, Connecticut which is preparing a shredded material to be used by United Illuminating Company in their Bridgeport Harbor plant. Twenty percent of the capacity is to be supplied by waste. The waste is mixed with oil in a one-to-ten relationship. So although we're using more combustion of solid waste, it is not going to provide anything like the amount that has been suggested here because it has to be burned in conjunction with fossil fuel and can only be burned in these cycling plants, and there are likely to be many, many problems in collecting it from suburban and rural areas.

I think first, we should begin with conservation which was not emphasized sufficiently in the paper, although it was cited at the end. This allows time; there's been considerable conservation in New England in the electrical consumption area in late 1973 and 1974. My state at least experienced reduced electrical use at the same time as output and employment levels remained steady or increased. However, the reduced demand can be attributed largely to the recession. But there is still probably a great deal of room to move and to provide for conservation, particularly in the commercial sector, which is the fastest growing consumer of electricity and other energy forms. Conservation has benefits in that it buys time and I think that in terms of finances, time is important although conservation in the short term does affect earnings. Conservation allows time for new technologies to develop. However, let us remember that reduced demand also has its price. It has a price in that while it removes wastefulness, it also removes part of the buoyancy of the American economy and part of the whole American character of expensiveness and the expanding-pie philosophy and practice which we followed successfully for many years. It will also result in more stringency in public expenditures. Even in the environmental area we may suffer: parks will not be bought and museums and cultural institutions will not receive the funds that they need to keep their programs going. So that is a double-edged sword but on balance, desirable.

The utilities here have planned a nuclear expansion program. Mr. MacKenzie says that over the next ten years there is no alternative to nuclear and coal.

Now over the longer term, by which I mean the year 2000, the question is whether we can rely on these technologies that have been discussed in the paper. I don't think so. It doesn't look as though for the large increments of power that are going to be required we can rely on solar, wind, and the coal-pacifying technologies unless we're willing to pay what I expect to be a nonacceptable price. So we must work within the most realistic course which is in the direction of a steadily expanding use of electricity and does permit a diversity and flexibility of supply which the other forms do not and within the economic constraints which are overwhelmingly important now. And we should have the same expectation that technology and good management will guide us in the nuclear area that the paper seems to assume will provide better solutions for us in the coal, wind, and solar area. Again, I don't see how we can say in one case technology, management and new developments will help and in the other it will not. The pie is not growing as fast as it did in the past which means that the groups which are concerned with bettering themselves are going to be increasingly ornery and concerned about increased prices, which means that we cannot play with technologies as expensive as some of those proposed here.

Response to Judd

James J. MacKenzie

In his opening remarks Mr. Judd states that environmental costs are 1) difficult to measure, 2) may be considered "good" or "bad" depending on the "experts," and 3) may cost too much to mitigate. I would certainly agree that environmental values are sometimes difficult to quantify. But it does not follow that these values do not possess great worth, irrespective of our poor ability to assign a dollar figure to them. Perhaps windmills should not be placed in the White Mountains because of the aesthetic damage that would result. When Professor Bill Heronemus asked me my opinion on the subject a half a dozen years ago, I suggested he look elsewhere, that these mountains were too valuable to New Englanders. It was at that point that he started looking more seriously at offshore systems.

Fortunately, not all pollution costs are as difficult to deal with as visual pollution. Mr. Judd's example of sulfur pollution is such a case. The fact that the exact effects of sulfuric acid air pollution on public health are still unknown is really not the point. The point is that for years consumers were getting "cheap" electricity while the elderly, the young, and asthmatics suffered and bore excessive medical costs. The differences in the intensity of fuel use from state to state account for the different sulfur regulations; each state is aiming at essentially the same air quality standards.

Mr. Judd's observation that water pollution abatement may not be worth the cost because swimming pools could be provided more cheaply is a classic example of how we have gotten ourselves into our present environmental mess. First, he *assumes* that industrial wastes do not pose a threat. Recent history shows that information is too scarce to be able to state this as a fact. Mercury wastes, asbestos tailings, PCBs, and other organic chemicals were all presumed innocent. They would stay where they were put. They would not affect public health. Yet scarcely a week goes by without some carcinogen being identified in our food or water, usually with no obvious source. Recall that 80 percent of human cancers are believed to be environmentally caused. If there is any lesson to be learned from the past ten years it is that we must be more cautious in our industrial activities. We must bear the added costs of pretesting chemicals before releasing them into the environment, or else we must not release them at all. In the absence of conclusive proof, we must take a conservative approach to environmental pollution and control it at its source.

This means meeting environmental standards, set as wisely as we know how, and paying the additional costs. These are the environmental costs to which I was referring.

Mr. Judd makes several other points on which I would like briefly to comment. He says that coal is not really a likely source for electricity in New England because of lack of transportation facilities, high cost, and lack of scrubbers. First, coal is now being burned in power plants in New England. Two-thirds of New Hampshire's electricity and about 6 percent of Massachusetts's electricity come from coal.[1] In a personal communication with the fuel buyer of a large New England utility, he assured me that if the utility were to commit itself to coal, it would buy its own mine and obtain coal delivered to New England at about $25 to $30 per ton. As I indicated in my paper, scrubbers in fact are being commercially used. There are over 100 scrubbers in operation, under construction or planned, with most to be in operation by 1977. But my own belief is that we would be better off removing the sulfur either before combustion, through solvent refining, or in a modified burning process, using gasifiers or fluidized beds. Commercial low-Btu gasifiers are now available and are in use throughout the world. They can be used here to produce clean electricity without air pollution.

As for floating wind turbines, I am always amused that the utilities cannot imagine them, yet have little difficulty in accepting floating nuclear power plants, first introduced in the comic strips about ten years ago.

With regard to solid waste, I suggested that solid waste could supply about 12 percent of our *electricity* needs, *not* total energy needs.

In his last paragraph Mr. Judd states that: 1) large increments of power are going to be needed; 2) that we cannot rely on coal, solar, or wind unless we are willing to pay an "unacceptable price"; and 3) good management will take care of the nuclear problems. My answers are that: 1) with any kind of a conservation program in this country, large increments in electricity demand will not occur, 2) that coal is or will soon be competitive with nuclear everywhere, including New England, and that without its many Federal subsidies nuclear power would not be competitive at present. The nuclear subsidies range from Federal insurance programs limiting the liability from accidents, to a host of unpaid social costs that we are simply deferring to future generations. And 3) because of the qualitatively and quantitatively more serious risks posed by nuclear energy a management effort far superior to what we have experienced over the past 30 years is needed to make it acceptable. The prospects of increasing the quality of the Federal management effort do not seem bright.

[1] *FPC News*, October 7, 1975.

Discussion

Louis Cabot*

I am Chairman of Cabot Corporation, which imports liquefied natural gas into Boston Harbor through its subsidiary, Distrigas Corporation. I would like to refute some of Dr. MacKenzie's statements.

First, I would like to tell you that I worked on that Smith-Putnam windmill in Vermont he mentioned back in the early forties when I was at college. I would like you to visualize a Boeing 747, standing on its tail on top of one of the highest mountains around in full view of the beautiful, rustic city of Rutland, Vermont, waving its wings around like arms. When the wind was really blowing, which would be some but not all of the time, the windmill would produce less power than one World War II single-engine fighter plane. You can draw your own conclusions as to how useful a system of such installations would be in solving our energy needs.

One image created by Dr. MacKenzie's paper concerned coal gasification, which he depicted as a socially more desirable source of additional gas than LNG. But if you really look at all the health hazards and environmental problems involved in coal gasification, with the constant dangers of men working underground, with strip mines devastating the landscape, with enormous consumption of precious fresh water, with new railroads criss-crossing the countryside, and with ever higher sulfur pollution going to the atmosphere, it is clear that the safety and environmental problems are as great and probably much greater than those for oil or gas.

There were other pieces of imagery, derogatory to LNG, used in Dr. MacKenzie's talk which did not appear in his printed paper. For example, he tried to arouse anti-Algerian feelings by evoking chauvinism and arousing us to the dangers of relying on foreigners for energy. The facts are that the amount of LNG to be brought into New England by Distrigas represents about 3 percent of the total gas consumed in the area its facility can service. That's not a tremendous exposure. Dr. MacKenzie appealed to our sense of economic outrage by talking about \$3 or \$4 per thousand cubic feet of gas when, in fact, the price is substantially less and comparable to imported oil per unit of energy. He frightened us by saying liquefied gas is tremendously concentrated, 600 to 1. The fact is that liquefied gas has a little less than the same amount of energy per gallon as gasoline, or heating oil, or propane, energy sources which Dr. MacKenzie

*Chairman of the Board, Cabot Corporation and of the Federal Reserve Bank of Boston. In addition, he is a director of many corporations and a trustee of innumerable institutions.

implied are not hazardous. He conjured up an image of 100 square miles of devastation. There is no realistic set of circumstances under which that could happen. He talked about a million and a half barrels of LNG being stored in Boston Harbor. This too is misleading because the storage is at several well-separated locations, and the biggest tank in the area holds 600,000 barrels, comparable to large oil storage capacities. Every opportunity was made to scare you. Is the use of imagery a sound method for arriving at balanced judgments about complex issues?

Cabot and all of the LNG industry have made careful studies of every aspect of LNG safety. Serious quantitative analyses always come to the conclusion that the critics are off by orders of magnitude. Of course, a large fire would be bad. Any large fire is bad. But enormous precautions have been taken to avoid fires, and to keep those that do occur small and under control. I object to the cavalier assumption that the LNG importer is insensitive to matters of public safety. Boston Harbor was selected after a tremendous amount of research. Remember that one of the issues is not to mar the beauty or disturb the ecology of any presently unspoiled coastline area. The site for the Distrigas tanks was a semi-abandoned gas works, already a gross eyesore in a long-standing industrial area. We worked with all the authorities who had any jurisdiction over siting, including the City of Everett authorities who very much welcomed it and the Coast Guard who have dealt with similar issues for years. Our objective was to make the facility as safe as humanly possible and to make the area more attractive than it was. This we have done.

The Coast Guard has taken special measures to avoid shipping accidents in connection with LNG ships coming into our harbors. It controls all traffic whenever an LNG ship comes into harbor and creates a completely traffic-free envelope around the ship, two miles ahead and one mile behind it. If under those circumstances a collision should somehow still take place, the collision could only be minor and the chance of a major spill infinitesimal. LNG tankers have a much safer hull design than ordinary gasoline or oil tankers. They have five feet of insulation and at least two separate skins between the cargo and the outside, compared to one inch of mild steel for ordinary tankers. Furthermore, the Navy, the Coast Guard, and the Air Force have conducted tests to determine how even large LNG spills on water and fire can be controlled.

Theoretical analyses of the worst possible case, the one Dr. MacKenzie described, have been done by many other careful scientists. They strongly refute his estimate of the size of the affected area and the number of casualties.

To supplement all the work by Distrigas, its engineers and contractors, and all the relevant government authorities, Cabot Corporation also set up an independent Safety Committee, reporting directly and independently to the parent company's board of directors, to review all matters of safety for the project. It was made up of engineers and scientists from universities, government, and industry, widely experienced in cryogenics, hazard analysis, and other related technologies.

The real issue is the relationship between the risks a facility creates and the benefits it produces. If you look seriously and objectively at risk-benefit analyses for the various energy systems, LNG is one of the safest.

I can only say that the public must some day realize it is being misled if if follows those who only forecast doom and discredit all serious efforts to find the best solutions for meeting real human needs.

Response to Cabot

James J. MacKenzie

At the beginning of his remarks Mr. Cabot dismisses the potential for wind to make any contribution to the solution of our energy problem. The power from a 1000 kilowatt wind turbine would be no greater than that from a World War II fighter he asserts.

According to the *Project Independence Report* (Solar Energy Task Force) there is a very large potential in the United States for extracting energy from this renewable resource. "An estimate of the expected amount of power which could be extracted from the wind over selected areas of the U.S. by the year 2000 has been calculated to be about 1.5 x 10^9 MWeH/year (Megawatt electric-hours/year). This is about 80 percent of the current U.S. demand for electricity. This is neither a theoretical maximum nor an optimum, but rather the most reasonable probable value yet calculated."[1] If the price of oil remains at $11 per barrel and if incentives were introduced, the report concludes that about one-fourth of our electricity could come from the winds by 2000.

Low-Btu coal gasification is also dismissed, primarily on what Mr. Cabot sees as safety and environmental grounds. First, I am the first to admit that there are problems in mining coal. And though, as Mr. Cabot suggests, they are greater than those of finding oil and gas we shall have to solve them since we have lots of coal, but very little oil and gas. The environmental and safety problems of mining coal must now be considered essentially political. Europeans have demonstrated that mines can be made safe and that most strip mines can be rehabilitated. Obviously those areas that cannot be rehabilitated, perhaps in the steep hills of Appalachia and in the West, should not be surface-mined at all. All that we really need to solve the problems of coal mining is an enlightened administration in Washington.

As for the other effects, very little fresh water is consumed in low-Btu gasification, as opposed to the manufacturing of substitute natural gas. On balance, "criss-crossing the countryside" with railroads can scarcely be considered a major environmental problem; rather, it is part of the solution to our energy problem to rehabilitate our railroads and reduce our dependence on trucks and planes. Also, as I indicated in my paper, scarcely any sulfur at all is released to the air from low-Btu gas production.

[1]Page IV-15.

Mr. Cabot reprimands me for suggesting that we should think long and hard before becoming dependent on imported LNG. My admonition was relatively mild: "In light of our recent experiences with imported oil one must question the wisdom of once again becoming so dependent on foreign sources. It is easy to imagine U.S. companies financing a huge, costly liquefaction, transportation, and storage network only to have the exporting countries arbitrarily and sharply raise prices or even nationalize the holdings." Actually some of this is already beginning to happen. In the fall of 1974 Libya broke its contracts with both Italy and Spain by arbitrarily raising its LNG prices. Both countries refused to accept the higher prices and shipments were temporarily suspended, to be resumed later only on a ship-by-ship basis. As for Algeria, the source of LNG for Mr. Cabot's company, it has recently begun to press for a "hardship" clause in its contracts that would permit renegotiation of contracts in the event of a "major change" in the natural gas market. U.S. firms oppose such a clause claiming that it effectively reduces the length of the contract to as little as two years. Some countries such as Indonesia are relating their price of LNG directly to the cost of oil and other competing fuels. Thus there is the distinct possibility that the price of LNG will rise as arbitrarily and capriciously as the price of oil. And once committed we will have little alternative but to go along.

Mr. Cabot implies that LNG is no more dangerous than gasoline or heating oil because as a liquid it has a similar heating value. The fact is that the heat content of LNG is not the issue here. There is, after all, two to three times as much energy in a pound of firewood as there is in a pound of dynamite though we certainly view the risks from the two differently. LNG and propane are much more dangerous than fuel oil or gasoline because large volumes can quickly evaporate, posing severe fire and explosion hazards. A small, primitive LNG facility exploded in Cleveland, Ohio in 1944, killing 133 people, injuring 300, and destroying or damaging 10 industrial plants, 80 homes, 200 automobiles, and the city's sewer system over an area of 30 acres. The flames from the fire and explosion of the 25,000 barrels of LNG reached an estimated one-half mile into the sky. And as Mr. Cabot states, there is a tank of 600,000 barrels capacity in Everett.

I certainly did not state or imply in my paper that the Cabot Corporation was not taking all the safety precautions that it could imagine. Nor did I say that LNG should definitely not be imported into the United States. But the fact remains that accidents due to events entirely beyond our control can and do happen. After an LNG ship has docked to unload, tanker traffic resumes in the harbor. Is it not possible that a ship might lose control and ram a docked LNG tanker and start a fire? The consequences of such a fire are still the subject of scientific investigation. There are honest disagreements on how severe it would be. In my view the Federal Power Commission, the Coast Guard, or some other Federal authority should undertake an independent safety analysis of LNG with

the goal of establishing siting criteria for large storage tanks. In the meantime I submit that it is only prudent to locate such tanks away from heavily urbanized areas. LNG facilities are clean enough so that their impact on less-developed areas of the coast could be made acceptable.

Discussion

Nuclear Safety: The Positive Side

R. Murray Campbell*

The negative side of nuclear power — the horrific imagery of suffering and devastation — needs no further publicity; allegations have been quoted and requoted until they have become axioms. What began as a responsible note of caution has become a strident campaign to mothball nuclear power.

But there is a very positive side to the issue — and it can be summed up in the assertion that the emphasis in the nuclear industry is on safety and quality, and it is not allowed to be subverted by considerations of cost, schedule, convenience, etc.

A peculiarity of the industry is that a minor incident, or a suggestion that an incident might occur as a result of some defect that has been uncovered, receives instant and widespread publicity while the follow-up story which invariably reveals the mountain as a molehill goes unnoticed. The first public act of the new Nuclear Regulatory Commission about a year ago — ordering re-examination of reactor vessel nozzles (piping connections) for cracks at several operating plants — is a good example. To the public, it must have seemed that a careless industry was nabbed in the nick of time by a regulatory body that should have been alert sooner. To those familiar with the facts, it was merely another expression of thoroughness with which every potential hazard is identified, investigated and negated.

The Nuclear Regulatory Commission (successor to the Regulatory Branch of the AEC) does not begin, it merely continues, a severe and competent regulatory interest in safety. Those of us involved in engineering and construction of nuclear plants saw no sign that our inquisitors from the old AEC were in any way softened by influence from the promotional arm of the AEC. However, it is true that with the passage of time, more and better techniques become available to assess engineered safety features.

The aspect of regulator versus applicant, with mountains of reports and testimony available for public scrutiny, sometimes seems capricious and inefficient, but it certainly is effective. As a result, the few accidents which have occurred have been minor, and there has been no radiation-related casualty or serious injury from about 300 operating-years of nuclear plants.

*Engineer. His current position with Stone and Webster Engineering Corporation is Project Manager responsible for engineering, construction, and cost control of a large nuclear power station now under construction.

All nuclear plants must be designed, constructed, and operated in a manner which avoids undue risk to the health and safety of the public and plant personnel. This means that consequences of radiological releases due to accidents and operations must be within criteria established by AEC Regulations.

The main design feature of a nuclear plant for protecting the public from unacceptable radiation exposures is the installation of multiple barriers between the prime source of radioactivity and the public. The source of this radioactivity is the fission products in the reactor fuel assemblies. The three major barriers between these fission products and the public are:

— The fuel element barrier, which encapsulates the fuel material and the fission products.
— The reactor coolant system boundary, which contains any leakage from the fuel elements.
— A containment structure, which encloses the major portion of the reactor coolant system.

The fuel material, the reactor coolant, and the distance between the reactor plant and the public also serve as barriers.

The most serious event conceivable is the loss-of-coolant accident. If the coolant, usually water, were lost because of a pipe rupture, an emergency core cooling system (ECCS) should still supply adequate coolant to the fuel elements to prevent their melting or bursting and releasing fission products.

The question of ECCS effectiveness has been a subject of debate for over three years. In 1971 the AEC published a set of guidelines for ECCS requirements. These were known to be very conservative and the transcript of public rule-making hearings filled 50,000 pages.

Questions still remain concerning the scope of the investigatory programs under way. Some intervenors say that without full-scale testing we will never know the true effectiveness of ECCS. If this is so, we will also never know the true effectiveness of other facilities and endeavors with low risks and high-fatality consequences of failure. For example, jet airliners are not tested to destruction and full-scale dams are not loaded to destruction.

In all these programs, models simulating the important parameters with appropriate scientific interpretations are used to develop final design and analytical methods before scaling to full size. This technique is well understood and has enabled us to progress to our present state of advanced technological sophistication without catastrophic accidents.

The industry hoped that the logic of the now famous Rasmussen report, which considers all sorts of permutations and combinations of failures and malfunctions of the nuclear system and accident mitigating systems, would convince people that the probability of serious impact on the public is negligible. Unfortunately, although none of the many criticisms of his report have any depth, they have detracted from its tremendous potential for placing safety in perspective. It shows clearly that no reasonable assumptions could bring the nuclear hazard to a single member of the public into the realm of probability that, say, the same member might be struck by lightning. Do the public and the press worry about multiple extermination by lightning?

The more sophisticated elements of the anti-nuclear crusade seem to be abandoning the ECCS and other safety issues related to reactor plant failures *per se*. The subject of the debate is turning more to the problems of sabotage, nuclear terrorism, and waste disposal.

The multiple barriers, the massiveness of the shielding and containment, the conservative and redundant design of safeguard features make effective sabotage difficult and mitigate its consequences if it did happen. However, nuclear facilities are now closely guarded and all administrative procedures and physical features are audited by regulatory authority, such that sabotage from without or within entails a high degree of risk with little prospect for significant effect.

Given the media's tendency to excite the public on nuclear hazards, nuclear terrorism admittedly could be extremely effective — if it could be carried out. Undoubtedly, we can expect it from sources outside the United States where strictures the United States places on the utilization of nuclear power would be ineffective. A well-developed nuclear industry and related public acceptance surely would enhance, rather than detract from, an ability to deal with such terrorists.

The popular notion is that any junior scientist can make a bomb and that the only hard part is stealing enough plutonium. Perhaps it isn't too hard to come up with a conceptual design of a bomb but it is quite another matter to manufacture it — especially, the delicate machining, handling, and fitting of many pounds of highly radioactive material. The terrorists would have to acquire a facility far beyond the means, patience, management, and technical skills they are likely to have.

Disposal of radioactive waste is more of a philosophical question than an engineering problem in that one can question the propriety of leaving the monitoring and guarding of certain long-lived wastes to future generations. But we also build high dams the continued integrity of which must be the responsibility of future generations, and if we exhaust our irreplaceable fossil fuels through lack of nuclear power, we have denied future generations the use of these fossil "fuels" for recyclable non-fuel uses.

Nuclear critics represent the scientific community as being overwhelmingly against nuclear power. The principal evidence is a petition signed by 2,000 "scientists" who oppose nuclear power. Not only do these signatories represent a small fraction of the nation's scientific and engineering community but few of them have intimate knowledge of how nuclear facilities are engineered and constructed. It is unfortunate that the public hears little about the positive side, and is aware only of well-publicized statements on the anti-nuclear side. Yet the regulations, the safety

analysis that accompanies each application for a construction permit, the searching questions and detailed answers which are part of the licensing process are all available for public scrutiny and demonstrate the thoroughness with which the industry and its regulators pursue safety.

Those interested in this subject may contact the author for a more detailed technical discussion and bibliography.

Response to Campbell

James J. MacKenzie

According to Mr. Campbell there are virtually no problems with nuclear energy. In particular, the Nuclear Regulatory Commission (formerly the Atomic Energy Commission) is an effective regulator; the Emergency Core Cooling Systems (ECCS) are conservatively designed; there are no criticisms of the AEC's Rasmussen report with "any depth"; it is extremely difficult to make a crude nuclear bomb, among other reasons because the material is "highly radioactive"; and the disposal of radioactive wastes is more a "philosophical" than an "engineering" problem. I disagree categorically with Mr. Campbell on each of these issues.

First, has the AEC been an effective regulator? The answer is a clear no, not only in reactor safety design, but in essentially every other nuclear activity that it has developed and regulated. A devastating history of the failure of the AEC can be found in Peter Metzger's book, *The Atomic Establishment*.[1] In it Metzger documents how the AEC failed to protect the American public from weapons fallout in 1950s; how it failed to protect underground uranium miners from excess cancer, when they were well known at the time; how the AEC refused to regulate the use of radioactive tailings in the southwest and allowed homes, churches, schools and hospitals to be built upon them; plus other examples involving nuclear airplanes, rockets, pacemakers, etc. It has been the rule at AEC, and not the exception, to mismanage the development of its programs and to permit unnecessary risk to the public health.

The failure to develop adequate, proven safety systems in nuclear power plants is unquestionably the AEC's most serious example of mismanagement. The fact is that the critically needed emergency core cooling systems have never been tested under even the simulated conditions of a severe accident. As a result their performance under accident conditions is still unkown. And without the ECCS performing, a serious pipe rupture could lead to a melt-down of the fuel and a rupture of the containment system surrounding the reactor vessel. The stage would be set for a major release of radioactivity of which the results to the public health would depend on wind direction and population densities.

[1]New York: Simon and Schuster, 1972.

According to Mr. Campbell the AEC in 1971 published "very conservative" guidelines for ECCS performance. What he failed to say was that the guidelines were for controversial computer models describing ECCS behavior, and not for the ECCS themselves. Although the AEC's official position was that the models were adequate to describe the ECCS, AEC's internal memos showed serious doubts on the issue within the agency. In 1972, at the peak of the ECCS public hearing, environmentalists, with the threat of a law suit, forced the release of a number of AEC internal memos on ECCS. According to *Nucleonics Week,* the weekly industry newsletter:

> Study of the recently released AEC internal documents on emergency core cooling reveals a strong measure of staff concern that: 1) the interim criteria on ECCS are not conservative enough; 2) that accident-condition factors such as coolant-channel blockage are not sufficiently understood or allowed for; 3) that experimental tests conducted so far have little or no relevance to the large reactors now being built; and 4) that computer codes used for calculating the results of a hypothetical loss of coolant accident (LOCA) are relatively crude, lack much needed data, involve too much "patching" between one code and another, were intended for 1965 and 1967 reactor designs, and should be replaced by much more sophisticated codes as soon as possible.[2]

The record of the ECCS hearing shows that the staff's qualms were well justified and that major accident phenomena were not even identified at that time, much less included in the ECCS computer models.

According to Mr. Campbell there has been no serious criticism of the AEC's reactor safety study (the Rasmussen report) which claims that nuclear accidents would be very unlikely to cause public harm. He apparently ignores the year-long, federally funded study of this report by the American Physical Society, the professional society of physicists. The APS study, completed in 1975, concluded that the AEC had vastly underestimated the number of cancer deaths that would result from a serious accident. More importantly, the physicists concluded that they did not "have confidence" in the techniques used by the AEC to predict nuclear accident probabilities. As for the ECCS codes, they observed that there is a danger that "the mere existence of extremely complicated computer codes, which few people understand, will lead to an overconfidence in reactor safety."

According to Mr. Campbell it would be difficult to make a crude weapon, in part because the material is "highly radioactive" and in part because the "terrorists would have to acquire a facility far beyond the

[2]February 17, 1972, p. 8.

means, patience, management, and technical skills they are likely to have." First, *neither* plutonium nor uranium, the materials from which bombs are made, is "highly radioactive." They are alpha emitters and as long as they are not breathed in or absorbed through a cut they can be safely handled for hours without any significant radiological hazard. Is it really so difficult to make a crude bomb? According to the most thorough public study on the subject, "Under conceivable circumstances, a few persons, possibly even one person working alone, who possessed about ten kilograms of plutonium oxide and a substantial amount of chemical high explosive could, within several weeks, design and build a crude fission bomb. By a 'crude fission bomb' we mean one that would have an excellent chance of exploding, and would probably explode with the power of at least 100 tons of chemical high explosive. This could be done using materials and equipment that could be purchased at a hardware store and from commercial suppliers of scientific equipment for student laboratories."[3]

Mr. Campbell also claims that nuclear plants are impervious to saboteurs. Suffice it to say that the bomb experts from the Massachusetts State Police told us, as members of the Massachusetts Commission on Nuclear Safety, that they could easily sabotage one with very little effort using high explosives. (This was in the spring of 1975 and the security situation at nuclear plants may have improved some over the past year.)

Lastly, Mr. Campbell states that guarding radioactive wastes for hundreds and thousands of years is no more necessary than guarding dams and the like. Unfortunately, dams break, drowning people who were unfortunate enough to live on the flood plains below them. And the AEC has allowed radioactive wastes to be stored in leaky old tanks and to be buried in trenches where they proceed to leakout and enter food chains. Neither situation is satisfactory, nor does one justify the other.

It is surprising that Mr. Campbell can state that the public hears little about the positive side of nuclear power. Every day we are barraged by advertising from the utilities, the reactor vendors, their trade organizations, and their government allies in ERDA. Why is it that the nuclear industry, with all its financial and political clout, cannot convince the press, the public, and the scientific community that it is right and that its critics are wrong? Perhaps it is because their case is weak. I can assure Mr. Campbell and other members of the nuclear industry that they need only put their house in order and solve the many problems, technical and otherwise, plaguing them. When this is done, their critics will go away.

[3]Mason Willrich and Theodore B. Taylor, *Nuclear Theft: Risks and Safeguards* (Cambridge: Ballinger Publishing Co., 1974), page 20.

The Potential for Coal Use in New England

Martin B. Zimmerman*

The large rise in oil prices has occasioned a reexamination of alternative sources of energy. Great interest is centered on the vast coal resources of the United States. Legislation being considered in the Congress would make it mandatory to burn coal in all new fossil fuel plants.[1] The Federal Energy Administration has recently ordered the conversion of existing oil plants where feasible to the use of coal.[2] In short, there is a great deal of optimism about the ability of the U.S. coal reserves to play a larger role in satisfying U.S. energy demands.

At one time in New England coal supplied an important proportion of electric utility fuel needs. As recently as 1966 about 10 million tons of coal were burned annually in the six states of New England. By 1973 this had declined to 1.3 million tons, the great bulk of which supplied one power plant in New Hampshire.[3] This steady decline in coal consumption was due to the availability of cheap imported fuel oil and to increasingly strict environmental regulations. It was cheaper to comply with sulfur regulations by burning oil than by burning coal. Has this situation now been reversed by the actions of the cartel of oil-producing nations? Will coal now be favored in New England power plants? It is this issue that we will address in this paper.

If coal is to make a contribution to solving the energy problems of New England, it will be because it is a less costly fuel than its competitors. The costs of coal must also include the environmental costs of production and use since society has demonstrated a willingness to pay for a cleaner environment.

*Research Associate at the Sloan School of Management and a staff member of the Energy Laboratory at the Massachusetts Institute of Technology. He is engaged in research in the economics of coal supply and coal-based synthetic fuels.

[1]See *Coal Age*, July 1975, p. 22.

[2]*Coal Age*, August 1975, p. 25.

[3]National Coal Association, *Steam-Electric Plant Factors*, 1974.

In what follows, we concentrate on the use of coal in electric power plants. This is the dominant use for coal today. Economies of scale in handling, transport and purchasing make it more costly to use coal in smaller quantities. If the potential for coal use proves to be limited here, it is unlikely to prove a satisfactory fuel for most industrial uses.

The Irrelevance of Reserve Statistics

The great optimism with regard to potential coal use that is reflected in public statements of government and industry officials stems from the vast coal resources distributed through major areas of the United States.[4] Total resources are truly staggering and could supply the entire United States with its energy needs for years to come. However, this is not really the issue. Coal "reserves" measure only what is in the ground and not how much it costs to mine and deliver. The important question is how costly will it be to use coal. The answer will differ from region to region of the United States since each region relies on different supplying areas and will have to pay different transport charges.

Dimensions of Price

The price of coal is not easy to estimate. Coal differs by sulfur content, heating value, ash content, and volatile matter. Furthermore, prices observed in the marketplace are for contracts of various time periods, and for delivery ranging from immediate delivery to three or even five years from the contract date. The latter contracts are the truly long-term contracts for they allow the development of new mining capacity. Unanticipated shocks in supply and demand would have no effect on the price of these long-term contracts. These are all important distinctions to bear in mind. A great deal of confusion arises because people, with different purposes, quote a "price" of coal.

In 1973 the spot price of coal increased dramatically. The sudden increase in the price of oil together with the embargo greatly increased the demand for coal. This was an unexpected development, one for which the coal industry was eager but unprepared. In face of the limited capacity in the industry for quick output expansion the increased demand led to a dramatic rise in prices of coal for immediate delivery as well as for contracts that specified delivery within a year or two. The price of coal in the short run was a poor guide to the future price. The direction of future prices was clear, however — the price would decline as new expansion took place as the industry adjusted to increased levels of demand. To be sure, prices, after the dust settled, might be higher than they were before the surge in demand but they would be lower than what was being earned by the coal industry in the period immediately after the embargo. Price

[4]See, for example, the optimism expressed in *Newsweek*, January 22, 1973, p. 53.

developments since that period bear this scenario out. Prices have declined, both spot and contract, from their record high levels of 1974.[5]

The long-run price is the relevant price for decisions about new capacity. The utility building a new plant has adequate time to sign a contract that stipulates initial delivery in four or five years. This is adequate for a coal company to develop an entirely new reserve and dedicate it to the power plant. This is not the case for the power plant required by the Federal Energy Administration to begin burning coal as soon as possible. In the latter case the utility must enter the spot market. It can, of course, sign contracts for coal deliveries in future years, but for the next few years it will be forced to buy coal at spot prices.

The time element is not the only dimension of price. Of particular importance is the sulfur content of coal. Low-sulfur coal earns a substantial premium over higher-sulfur coal. Here again one should not be misled by the large "reserves." There is a lot of low-sulfur coal in the ground. However, it is in thinner seams and lies deeper in the ground than does the high-sulfur variety. This fact simply reflects geology and the working of economic processes. Since low-sulfur coal was valued by users for its noncorrosive, nonpolluting aspects, coal mining companies sought it out. This selection, coupled with a niggardly nature meant that mining proceeded more rapidly into deeper and thinner and consequently, more expensive-to-mine seams.

National Policies Affecting Coal Prices

New England is a small purchaser of coal. Even if present use of coal expands dramatically, total New England purchases will amount to only a small fraction of U.S. output. In short, with respect to the national coal industry, New England will have no effect on coal prices.

There are, however, important national policies that can have a significant impact upon coal prices faced by New England. The most important of these deal with strip mining and with air pollution controls.

Strip mining is a mining technique whereby coal is obtained by removing the overburden material above a coal seam with large shovels, draglines or bulldozers. Then, using smaller shovels, coal is removed. Strip mining occurs in all three major coal-producing regions — Appalachia, the Middle West and the Far West. However, its environmental impact is different in each of the areas. In much of Appalachia the terrain is hilly and strip mining is very disruptive of the contour of the land. Reclamation is possible, but expensive. In the Middle West the land is flat and the restoration of the original contour is easily and relatively cheaply accomplished. In the Far West the problem is different. The land is flat and arid. The contour of the land is easy to restore, but the vegetation presents a problem. It is unclear at present how easily or how cheaply the

Coal Week, July 28, 1975.

original vegetation can be restored once the delicate balance has been disturbed. A recent report by the National Academy of Sciences indicates that ten inches of rainfall is enough to allow restoration.[6] Many of the coal areas in the west receive this amount of rainfall, yet mining prohibitions are still hotly contested.

President Ford has twice vetoed legislation that would limit strip mining, but some form of control is likely to emerge eventually. Depending upon the restrictiveness of the law, it can have an important effect on the cost of strip mining and thus on the price of coal.

The other piece of environmental legislation that impacts upon the cost of coal is the Clean Air Act of 1967 and its amendments of 1970. This act set antipollution standards. The various states and municipalities then established standards on particulate and sulfur emissions. The regulations regarding particulates can be satisfied, in most cases, with the use of some form of mechanical control device at the power plant. Technology for the control of sulfur dioxides, however, is not as well developed. At present, the status of stack-gas scrubbing devices is subject to much controversy. Scrubbers are costly devices with no history of proven effectiveness and reliability.[7] In the absence of a mechanical control, in order to comply with air pollution standards, particularly the more stringent standards for new plants, a utility would have to burn low-sulfur coal.

These two environmental goals interact with each other. Major supplies of low-sulfur coal lie west of the Mississippi River, much of it available only through strip mining. Legislation that restricts strip mining will then have the effect of diminishing the supply of low-sulfur coal. There is a tradeoff that the United States must make between these two valid environmental objectives, for the stricter strip mining controls are, in the absence of a low-cost scrubbing technology, the higher the cost of reducing sulfur dioxide emissions. Clean air in the cities at low cost comes at the expense of strip mining in less urbanized areas.

With this as background, we can now turn to an examination of the options for New England.

FOB Prices

High-Sulfur Coal. It is difficult to estimate a relevant price of coal today. We don't have any estimate of truly long-run contracts. Reliable

[6]National Academy of Sciences, *Rehabilitation Potential of Western Coal Lands: A Report to the Energy Policy Project of the Ford Foundation* (Cambridge, Mass.: Ballinger Publishing Company, 1974)

[7]This, of course, can change over time. A recent article indicates technical success with scrubbers for six months on a power plant in Kansas. *New York Times*, September 7, 1975, p. 21.

statistics are not collected, and we can only trace out likely prices based on cost studies of the Bureau of Mines and reports of recently signed contracts.

In 1973, before the coal market was thrown into the chaos described above, high-sulfur (about 2 percent) eastern coal was selling for $8.75 per ton in West Virginia.[8] This represents the last observation on prices in a period when supply and demand were close to long-run equilibrium. As such, it represents the best base for estimation of what high-sulfur coal prices will be once the industry has had a chance to adjust to the higher levels of demand. Of course, significant changes have occurred to drive up the long-run price in 1975. About 40 percent of the 1973 price represented labor costs. These costs have risen significantly with the new union contract of 1974. Estimates place the increase at about $2-$3 per ton, which together with the 1973 labor cost of $3.50 yields a labor cost of $5.50-$6.50 per ton.[9] The remaining costs we escalate by 44 percent to reflect increases in the cost of mining machinery and equipment as recorded in the wholesale price indices. This yields a price of about $14 per ton at the mine mouth.

This cost is below the price for new contracts signed by the TVA in the Middle West. These contracts were in the $15-$16 per ton range, but these contracts can be expected to reflect the recent market tightness.[10] Expectations of the TVA are for a further decline in contract prices.[11] Depletion, that is the movement to costlier seams, has been ignored in this estimate since our own research indicates that depletion in high-sulfur coal has been small.[12]

Low-Sulfur Coal. The situation with low-sulfur coal is more complicated. For coal with less than 1 percent sulfur, depletion has been significant. The supply of low-sulfur coal is not as elastic as the supply of the high-sulfur product. The air pollution regulations in various states and municipalities have forced the use of coal low in sulfur content. The cost of mining this coal at the margin, or what is the same thing, the cost of expanding production, is much greater than for high-sulfur coal. This coal earns a premium relative to high-sulfur coal. Furthermore, much of the low-sulfur coal available in the eastern states is of metallurgical quality

[8]See M.B. Zimmerman, "Long-Run Mineral Supply: The Case of Coal in the United States." Ph.D. Diss., MIT, August 1975. This is also corroborated by R.L. Gordon, *The Competitive Setting of the U.S. Coal Industry (1940-1980)*, 1975.

[9]See, for example, *Coal Age*, January 1975, p. 57. Total cost over three years was estimated as $4.6 billion. Expected production is about 1.8 billion tons so that a per ton cost is $2.55. For relative importance of labor costs, see U.S. Bureau of Mines, Information Circular 8632, 1974.

[10]*Coal Week*, May 12, 1975.

[11]*Coal Week*, July 21, 1975.

[12]Zimmerman, *op. cit.*, p. 195.

suitable for making coke. The need for this low-sulfur, low-ash coal is forcing some eastern utilities into the metallurgical coal market and a similar situation would face New England utilities seeking supplies of coal low in impurities. The highest quality metallurgical coal sells on long-term contract for $50 per ton.[13] These are coals low in sulfur and ash as well as volatile matter. The latter quality is important in coke production.

While no firm price information exists for lower-quality metallurgical coal, there is evidence that it is in the $30 per ton range.[14] There is another important source of low-sulfur coal — the states west of the Mississippi River. This coal is low in heating value but also low in sulfur. It occurs in large deposits close to the surface so that mining costs are low. Its disadvantage is its location, which when coupled with its low heating value, makes transport cost per heating unit quite expensive. Nevertheless the high prices of eastern low-sulfur coal make it an attractive alternative to some eastern utilities. American Electric Power, for example, has contracted for large quantities to be used in its plants in Indiana, and now it will be moving into plants in the Ohio coal fields.[15] This is the American equivalent of "hauling coals to Newcastle."

The price of western coal delivered to a New England utility sets an upper limit on the price it would have to pay for low-sulfur coal in the long run. Western coal, because of its low heating value might not be compatible with existing boilers designed for high-quality eastern coal. For the new plant, where the boiler design is still flexible, it represents a real alternative.

Currently, western coal is selling for $6 per ton at the mine mouth in Montana.[16] This price also reflects short-run capacity constraints imposed by limited government leasing, uncertainty with regard to the future course of legislation dealing with strip mining and environmental suits that are holding up the issuance of mining permits. Were these obstacles to be removed, price could be expected to decline. Recent engineering estimates of the costs of mining put the cost, including a 12 percent after tax rate of return, of new western strip mines at about $4 per ton.[17] New

[13] *Coal Age*, May 1975, p. 30 and February 1975, p. 22.

[14] *Ibid.* Contract prices are mentioned as $20-$25 for coal with about 1.5 percent. We have therefore assumed 1 percent sulfur coal at a cost of $30.

[15] For American Electric Power purchases see *Wall Street Journal*, Sept. 24, 1972, p. 11, Nov. 5, 1973, p. 8, and Aug. 15, 1974, p. 14. The shipment into the area of Ohio will be announced soon. Information was provided by an executive of the railroad that will haul the coal.

[16] A recent contract for coal with 19.2 million Btus per ton was signed at a price of $7 per ton. Converting it to a per-ton cost for coal with 17-million Btus per ton yields $6. *Coal Age*, December 1974, p. 21. A contract for $5.26 per ton was announced in early 1975, *Coal Age*, February 1975, p. 22.

[17] This figure comes from U.S. Bureau of Mines, *Basic Estimated Capital Investment and Operating Costs for Coal Strip Mines*, IC 8661, 1974. The costs were presented as of 1973 and, adjusting for inflation in the mining machinery and equipment index, yields $3.83.

taxes in western states together with expectation of more stringent reclamation requirements suggest a price of about $5 per ton at the mine mouth for a long-run contract.

Transport Costs and Delivered Prices

Transport costs comprise a significant fraction of the delivered costs of coal. The most efficient means for transporting coal when water transport is unavailable is shipment by unit train. These are trains that are dedicated to hauling coal between a mine and a power plant. The cost of switching cars is avoided and administrative costs are reduced considerably. Further, the cars and locomotive are in almost constant use, greatly increasing utilization rates.

Rates are not set exclusively by the cost of the haul. Railroads in the past have been able to discriminate, charging utilities with higher cost alternative fuels and no alternative to rail transport more than utilities with less costly alternatives for a haul of any given distance.[18] Consequently, the rate pattern differs from area to area.

The best estimate of probable unit-train rates for new shipments from Appalachia to New England is the rate on the large-volume train shipment with fast loading and unloading to the Merrimack Plant in Concord, New Hampshire. In railroad-owned cars, the rate is $7.85 per ton or about 8.9 mills per ton-mile from Pennsylvania.[19] In reality, this represents a low estimate for new rates, since it was agreed upon when the real price of oil was far below what it is today. If past history is a guide, the higher prices of alternative fuels, in this case oil, could well lead to higher unit-train rates.

Western transport rates are even more complicated. Western coal is now moving into the Ohio Valley, but midwestern roads, in an effort to protect their local markets, appear to be establishing high rates for their portion of the haul.[20] A similar situation could arise in shipments further east, but it is too early to tell. The lowest rate likely to emerge for western shipments is 7 mills per ton-mile to the midwest and 8.9 mills per ton-mile for the continuation to the east. The 7 mill figure represents the low end of rates on shipments originating in the west.

Water shipment offers an alternative to New England coastal stations. This would involve an initial shipment by rail and transloading at the port. Some savings could be realized here, but the more circuitous route and transloading make costs about the same for an all-rail shipment at

[18] Zimmerman, *op. cit.*, ch. 3.

[19] The Pennsylvania and Lake Erie tariff specifies 4 hours loading, 10 hours unloading, 9,000 tons per train and a minimum of 900,000 tons per year.

[20] Zimmerman, *op. cit.*, ch. 3.

Table 1

A. Transport Costs to New England
($ per ton)

Source	Destination Hartford	Destination Concord
Northern Appalachia	$ 5.34	$ 7.85
Southern Appalachia	7.12	9.97
West	19.89	22.56

B. Mine Mouth and Delivered Costs

	Mine Mouth Cost Per Ton	Delivered Btu Content (mm)	Hartford Delivered Cost Per Ton	Hartford Delivered Cost Per Million Btus ($)	Concord Delivered Cost Per Ton	Concord Delivered Cost Per Million Btus ($)
Northern Appalachia (2% sulfur)	$14	(24)	$19.34	($ .81)	$21.85	($ .91)
Southern Appalachia (1% sulfur)	30	(25)	37.12	(1.48)	39.97	(1.59)
Metallurgical Coal	50	(25)	57.12	(2.28)	59.97	(2.40)
West	5	(17)	24.89	(1.46)	27.56	(1.62)

Source: Text. Transport costs are all-rail rates. Mileage from Rand McNally, *Handy Railroad Atlas*, 1973.

the rates cited above.[21] Water transport can be important though as a competitive tool for keeping rail rates low. We return to this point below.

Table 1 summarizes the above information. It shows that the cost of coal per million Btus delivered to New England ranges from 80¢-90¢ for high-sulfur coal and $1.40-$1.60 for low-sulfur coal. Low-sulfur Eastern coal would most likely come from southern Appalachia so that in addition to a higher mine mouth price, the transport cost would also be greater.

These costs probably represent the minimum New England would have to pay. Transport costs, depending upon the outcome of bargaining between railroads and utilities, could in fact be much higher. Further, real wages in coal mining have been escalating rapidly. A continuation of this process could increase costs significantly. It is instructive to compare these minimum estimates to alternative fuel prices.

Coal as a Base-Load Fuel

At present, oil delivered on new contracts in Massachusetts is in the neighborhood of $1.80 per million Btus. This is much higher than high-sulfur coal costs and comes close to the delivered cost of low-sulfur coal.

Electric power generated by nuclear plants is more capital intensive than alternative generation methods, but fuel costs are insignificant. The difference between the total costs of nuclear power and the nonfuel costs of coal sets an upper limit on the amount utilities will pay for coal before turning to nuclear power. Table 2 presents the implied limit on coal prices for various differences in the capital costs of nuclear and coal plants. The figures were generated by first calculating the additional cost per kwhr implied by the capital cost differential. This cost differential was converted to a cost per million Btus input equivalent. The latter figure is the result of multiplying the cost per kwhr by the number of Btus required to produce a kwhr.[22] This yielded an equivalent price per Btu which was multiplied by one million to yield cost per million Btus. Differences in operating and maintenance costs were also taken into account.[23]

Table 2 suggests it would take a price difference of at least $250 per kw between a coal and nuclear plant to justify the building of a coal plant in New England, since delivered cost of coal is at least 81¢ per million

[21]It is difficult to get an estimate of cost of large-scale bulk transport since coastwise coal shipments to New England ceased a number of years ago. Rough estimates for a coastal bulker on a run to New Haven suggest little or no savings. In more northern sites, water transport might provide some moderate savings.

[22]This is the "heat rate," assumed here to be 9,000 Btus.

[23]These come from the Federal Energy Administration *Project Independence Report*, Nuclear Volume, p. V-22 and Facilities Volume, p. VII-144-210. Operating and maintenance cost for a coal plant assumes no scrubbers and is the cost of burning low-sulfur coal.

Btus for *high-sulfur* coal. This is below the estimated difference of $150 per kw in late 1974 of the Federal Energy Administration for a coal plant without scrubbers. If the cost of the scrubbers is included, the FEA has the difference narrowing to only $80.[24]

These numbers are highly conjectural. They do not consider the total costs of unexpected delays in licensing nuclear plants since they ignore the costs of using an inefficient plant mix during the period when the nuclear plant would have been operating. Nevertheless, Table 2 suggests that in the absence of a dramatic reversal in the comparative costs of nuclear and coal plants, the base load alternative in New England will be nuclear.[25]

One event could drastically change this panorama — a nuclear moratorium. Then coal would obviously be used, but at cost levels above those estimated here. In this case, increased demand for coal would drive up prices and all bets are off as to how high the price of coal would go.

Table 2

Allowable Cost of Coal for Various Capital Cost Differentials (in cents per million Btus)

Advantage of Coal Plant in Capital Cost per Kw	Capacity Factors for Both Plants .65	.75
$ 50	25.6	23.4
100	42.2	37.7
150	58.8	52.1
200	75.4	66.5
250	92.0	80.9

Source: See text.

Notes: Assumes 17 percent annual capital charge. Adjustment for differential O & M costs as described in text. Assumes no scrubbers and therefore no additional operating and maintenance cost due to their use, a bias in favor of coal plants. The table assumes no difference in capacity factors for the plants. Available data are confusing on this issue and there appears to be no presumption that one plant will achieve a higher factor than the other, particularly if coal plants must use scrubbers which will reduce their availability somewhat. See source cited in footnote 24.

[24] *Ibid.* A recent report indicates a differential of $150 per kw between a nuclear plant and a coal plant with scrubbers in early 1975. Arthur D. Little, Inc., *Economic Comparison of Base Load Generation Alternatives for New England*, report prepared for New England Electric Systems, January 1975.

[25] Gordon reaches a similar conclusion for the United States, Gordon, *op. cit.*

Other Roles for Coal in New England

Eliminating coal from new base-load generation is saying a great deal, but it does not mean that coal resources have no role to play in New England. There are potentially three areas in which coal can provide an important part of New England's fuel supply.

(a) Coal plants, because of the shorter lead time in construction than nuclear plants, will provide capacity where demand has been underestimated. In light of recent cancellations of new orders and great uncertainty about future electric demand, this could prove important. The advantage of coal over oil capacity depends upon whether low- or high-sulfur coal may be burned. We return to this issue below.

(b) Coal conversion. The Federal Energy Administration recently estimated that over 3,300 MW of capacity could physically be converted to coal.[26] This capacity represents one-third of New England's fossil capacity and 36 percent of its fossil generation. These figures overstate somewhat the oil savings that can be realized in the future. As nuclear capacity comes on stream, the older fossil fuel plants will be pushed up the load curve. That is, they will be used to satisfy demands for electricity other than base load and their operating rates will go down. Nevertheless, in the period until the nuclear capacity comes on stream, coal can substitute for substantial quantities of oil.

(c) Finally, for new, intermediate load plants that must be constructed, coal offers an alternative to oil.

Policy Choices Involved in the Use of Coal

A. *The Environment Trade-off*

In all the cases described above, coal can substitute for oil. This serves the goal of limiting New England's dependence on oil. But it does not guarantee a lower-cost fuel. The costs of low-sulfur oil and low-sulfur coal discussed above are almost equal. When the costs of conversion for oil-fired plants are added, the difference could disappear for many existing plants. Furthermore, real oil prices could go down in the future. Voluntary conversion to coal will occur only if sulfur-in-fuel standards are relaxed. The present .5 percent standard in Connecticut and 1 percent in Massachusetts, where the bulk of the electric load is, insures this result.

The conclusion is not modified even if scrubbers are proven reliable in the near future. They represent an equivalent cost of 55¢ per million Btus in a new plant.[27] The costs of low-sulfur coal or high-sulfur coal plus

[26] *Federal Energy Administration Factsheet*, "Breakdown of Power Plants Being Considered for Conversion," May 9, 1975.

[27] This allows for a $75/kw cost of a scrubber and additional operating and maintenance costs. The additional O & M costs come from comparing a coal plant burning low-sulfur lignite and a plant using high-sulfur bituminous with scrubbers. Costs are from *Project Independence Report*, Nuclear Volume, p. V-22.

scrubbing are therefore roughly equivalent. If scrubbers are to be put on old plants with shorter lifetimes, scrubbing costs will be greater than low-sulfur coal costs.

This is a policy choice that each state must make. Coal will substitute for oil only at the cost of relaxed pollution standards. Low-sulfur coal can be burned and reduce dependence on oil, but it will not significantly lower costs and in many cases could raise them. Each state must determine its tradeoff between pollution, power costs, and the unreliability of oil supply. Table 1 indicates that a 1 percent sulfur-in-fuel standard will add 60¢ per million Btus burned when compared to coal with roughly 2 percent sulfur. If it is decided that pollution standards can be relaxed, they must be permanently eased for those power plants in question. If costs are to be low, assurance must be provided to allow a long-term contract and unit-train transport. Temporary variances will not be effective. There is some flexibility since not all plants need lower standards. Where plants are unable to take advantage of lower-cost coal, standards need not be relaxed. Low-sulfur oil can continue to be required.

B. *Should Conversions be Forced?*

The implication of Table 1 is that conversion, under current sulfur standards, will not be voluntary. This raises the issue of whether it should be forced. If utilities are forced to convert, dependence on potentially unreliable sources can be lessened. The FEA has opted for this route. There is, however, a danger in forcing conversion. As described above, coal transportation costs are affected by the alternatives available to a utility. The price of oil sets an upper limit on the delivered cost of coal a utility is willing to pay. If oil is eliminated by fiat, this upper limit is removed. Oil, at present, is a high cost alternative, but an upper limit nevertheless. If oil prices move down, this would be even more important.

Furthermore, it is not clear that conversion to coal is insurance for New England against the disruptions of embargo. During the period of rapid rises in coal prices, many utilities complained of nondelivery on coal contracts as supplies were allegedly shifted to the temporarily more profitable spot market.

Measures for Reducing Costs

If coal is used, an important area for keeping costs down is transport cost. One way to keep down transport costs is to explore the use of water transport for coastal plants as a means of promoting competition for the railroads. In the past, a great deal of the coal used in New England came through tidewater shipments. The coal originates on a rail line and there will still be a lack of competition at the origin, but by looking widely for coal and increasing the number of railroads that can originate tonnage, some competition there can be introduced. Unit-train rates are substantially less expensive than other forms of rail transport. Small plants often will not consume enough coal to justify large scale unit-train shipments and long-term contracts. In those cases, an alternative might be to combine fuel purchasing on a regional level. A single mine could supply a group of plants. A unit-train need service only one plant per trip, but service several destinations on a regular schedule.

Coal Conversion

Coal can be converted to high and low Btu gas. Work is proceeding on synthetic oil technologies. At present, these technologies are very high cost sources of energy. It is estimated that high Btu gas costs are now $4 per million Btus at the site of manufacture.[28] We might eventually turn to this source for space heating, but it is a future more to be feared than welcomed. Low Btu gas could be produced at New England sites for about $2.10 per million Btus.[29] Since the latter product is low in heat content, transport cost per heating unit is expensive and the gas would be produced at the site of consumption. There are economies of scale in coal conversion and this cost is attainable only for large plants producing about 250 billion Btus per day. It would therefore be a base load alternative, but a high cost one. It might eventually prove more valuable as an industrial fuel where industries are grouped together and collectively use this quantity of gas. In the next ten years, coal conversion offers small promise.

Summary

The original reason for the movement away from coal in New England is still with us. The OPEC cartel has not changed that fact. The costs of using coal depend importantly upon the sulfur standards set by each state and the Environmental Protection Agency. Short of a modification on the permissible levels of sulfur emissions, coal will not voluntarily be burned in significant amounts in New England's boilers. If the choice is made to relax these standards, attention must be paid to promoting competition as much as possible. Present conversion technologies also appear to be of limited value to New England.

[28] *Coal Age*, June 1975, p. 36.

[29] Capital and operating costs from M.I.T. Energy Laboratory Policy Study Group, *The FEA Project Independence Report: An Analytical Review and Evaluation*, Energy Lab Report No. MIT-EL-75-017, May 1975, p. 8-2. Coal cost from Table 1. Capital cost escalated from 1973 prices by construction machinery price index and operating cost by the wholesale price index.

Discussion

Guy W. Nichols*

When Frank Morris asked me to present a critique of Dr. Zimmerman's paper I was deeply concerned, because of my long-time affiliation with MIT and my fear that I would be in violent disagreement with an academician's approach to the use of coal in New England.

My concern was not justified. In fact, I have no criticism of Dr. Zimmerman's paper — it is excellent. I would, however, like to respond to his suggestion that we range widely for our coal so as to present our U.S. suppliers with adequate competition. Within the last year and a half, we in New England have burned coal from South Africa, Australia, and Poland. I don't think we can range much further than Australia. That's all behind us now, however, because we were not able to convince either Congress or the Administration to modify their environmental rules to permit us to burn coal past June 30 of this current year.

I would like to expand on three points that are covered in Dr. Zimmerman's paper:

1. Western coal may not be compatible with existing boilers designed for eastern coal.
2. Unless the Environmental Protection Agency (EPA) modifies permissible sulfur emissions, New England public utilities will not voluntarily burn coal in significant amounts.
3. In the absence of a dramatic reversal in the comparative costs of nuclear and coal plants, the base-load alternative in New England will be nuclear.

To provide background for my remarks I would like to review some tables with you.

Table 1 shows present Massachusetts sulfur regulations for plants located outside the Boston metropolitan area. For existing units the standards permit the emission of no more than 0.55 lbs. of sulfur per million Btus of heat generated. For eastern coal with a heat value of approximately 13,600 Btus per pound this is equivalent to an allowed sulfur content of 0.74 percent by weight. For western coal the standard permits only

*President and Chief Executive Officer, New England Electric System and Chairman of the National Association of Electric Companies. He has testified at numerous Senate and House Hearings on air quality, fossil-fuel policy and capital needs of energy companies.

Table 1

CURRENT MASSACHUSETTS SULFUR REGULATIONS
(OUTSIDE BOSTON METROPOLITAN AREA)

	Existing Units 0.55 lbs. of Sulfur/MMBtus	New Units 0.40 lbs. of Sulfur/MMBtus
Equivalent to sulfur Content by Weight for:		
Oil	1.00%	0.73%
13,600 Btus/lb. Coal	0.74	0.54
8,000 Btus/lb. Coal	0.44	0.32

Note: The existing units at the Brayton Point plant were designed for 13,600 Btus/lb. coal with 1.8 lbs. of sulfur/MMBtus. MMBtus = 1,000,000 Btus.

0.44 percent sulfur because of this fuel's much lower heat value. To appreciate the severity of these regulations one must realize that our Brayton Point plant, our largest and most modern plant capable of burning coal, was designed to burn coal with 13,600 Btus per pound and a sulfur content of 2.4 percent. The standards for new plants are even more stringent.

Can we meet these environmental standards in our existing plants? The coal most readily available to us that can meet existing regulations is western coal, which has a sulfur content of approximately 0.4 percent. Unfortunately this coal averages about 8,000 Btus per pound — far less than the 13,600 Btus per pound of coal our boilers were designed to use. We cannot physically burn enough western coal per hour to permit us to get the full capacity out of our existing plants. In fact, our best engineering estimates indicate a 25 percent reduction if we use western coal.

For a plant the size of Brayton Point this means a reduction of some 280,000 kilowatts. This is base-load capacity that would need to be replaced at a cost in excess of $150 million. This capacity penalty rules out western coal.

Eastern coal, while it has an acceptable heat value, can only meet the sulfur standards if it is high quality metallurgical coal or if scrubbers are installed. However, metallurgical coal is eliminated from consideration by a price of $50 per ton.

Table 2 outlines the capital costs that we may have to incur if we burn coal at our Brayton Point plant. The extent of these expenditures will be determined in part by the type of coal available and by the dictates of the then environmental authorities.

Flue gas desulfurization facilities account for more than half of the total costs of conversion, or $120 per kilowatt. The cost of these scrubbers

Table 2

POTENTIAL INCREMENTAL CAPITAL COSTS
TO BURN COAL

90% COAL FIRING

Brayton 1-2-3 Only

Pulverizers	$ 15 Million
Ash Handling	10 Million
New Coal Receiving and Handling	15 Million
Balanced Draft Work on No. 3 Other Boiler Work	10 Million
Miscellaneous Dual Firing Station Service Flue Gas Conditioning	8 Million
Precipitators	57 Million
Sub Total	$115 Million = $100./kw
Capital Costs — Scrubbers	$138 Million = $120./kw
Total Capital Costs	$253 Million = $220./kw
Original Plant Cost	$135./kw

more than offsets the economic advantages of burning eastern high sulfur coal and re-enforces the point that "unless the EPA modifies permissible sulfur emissions, New England public utilities will not voluntarily burn coal in significant amounts."

On the subject of sulfur regulations, I would like to emphasize our industry's commitment to meeting the SO_2 standards that have been set by our Federal environmental protection authorities. As you may remember, these are ambient standards and not plant emission standards. They address themselves to the ambient air, the air we breathe, and they set standards that this ambient air must meet. To be exact, they set primary standards sufficient to protect public health, and more severe secondary standards to protect public welfare as well as public health.

Our industry is committed to the attainment of both of these standards. We do ask, however, that we be allowed to attain these standards by the least expensive methods that we can devise. Our proposed methods include fuel switching, the use of tall stacks and, in some cases, the use of scrubbers.

We are not anti-scrubber. Although they are inefficient and largely untested, in some areas we anticipate their use will be required to meet our objectives.

The environmental bureaucracy of this Nation, both state and Federal, would, almost uniformly, like to have us go beyond the attainment of these Federal standards and achieve the even higher standards set forth in many of the various state implementation plans — and they would like to have us meet these standards without resorting to fuel switching, tall stacks and the like.

I have three tables that describe the difference in the results of the industry plan and what the government officials would like. The latter I have referred to as the EPA plan. Table 3 points out the differences in capital costs between the two plans. Under the utility plan 1980 capital costs for the industry are estimated to be $156 billion, of which $6 billion would be for equipment needed solely to meet the environmental standards. However if the government refuses to accept the industry's methods of meeting these standards this environmental component would more than double, raising the total capital requirements to $164 billion.

Converting plants from oil to coal increases costs under both plans, but particularly under the EPA version because of the higher sulfur content of most coal. If all plants were converted to coal, a step required in order to meet project independence goals by 1985, it would increase capital requirements $28 billion under the industry plan and $38 billion with the EPA version.

Table 4 lists the wasted annual costs of electrical production if we are forced to go the EPA route. And Table 5 describes the impact on coal demand and scrubber equipment demand if the utility approach is used — as compared with the impact if the EPA approach is used.

I am very pleased to report that there has been a very recent change in the thinking of the EPA at the Federal level. Roger Strelow, Assistant Administrator for Air and Waste Management, has recently indicated his support of fuel switching, tall stacks, etc. (the industry's recommended approach) for coal-burning plants through the year 1985. This is the first "crack in the door." It would be a little illogical for EPA to recommend this, and not recommend it for oil-fired plants as well — particularly when you realize that the oil-fired plants tend to be in those parts of the country with relatively clean air.

The third point of Dr. Zimmerman's that I would like to emphasize is "in the absence of a dramatic reversal in the comparative costs of nuclear and coal plants the base-load alternative in New England will be nuclear." I agree completely. There are obvious problems with all forms of energy production and energy conversion. Coal has some problems that do not

Table 3

ESTIMATED 1980 CAPITAL COSTS
(Billions of 1980 Dollars)

	Industry Plan	EPA Plan
No Conversions		
Environmental	5.8	13.5
Conversion	—	—
New Capacity	150.0	150.0
Total	155.8	163.5
FEA Recommended Conversions		
Environmental	5.8	17.1
Conversion	0.6	0.6
New Capacity	150.0	150.0
Total	156.4	167.7
All Plants Convert[1]		
Environmental	7.2	25.2
Conversion	26.5	26.5
New Capacity	150.0	150.0
Total	183.7	201.7

[1]Required to meet project independence goals.

Table 4

WASTED ANNUAL COSTS
OF ELECTRICAL PRODUCTION IN 1980
UNDER THE EPA PLAN[1]
(1980 Dollars)

No Conversions		
	$ Billions	5.3
	Millions/kwh	1.7
	$/Household	66.0
FEA Recommended Conversions		
	$ Billions	6.3
	Millions/kwh	2.0
	$/Household	76.0
All Plants Convert		
	$ Billions	8.8
	Millions/kwh	2.9
	$/Household	111.0

[1]The wasted cost of electrical production is attributable to the additional capital cost and reduced capacity caused by the EPA plan.

Table 5

1980 COAL DEMAND
AND SCRUBBER EQUIPMENT DEMAND
(Scrubber Equipment Demand in MW)

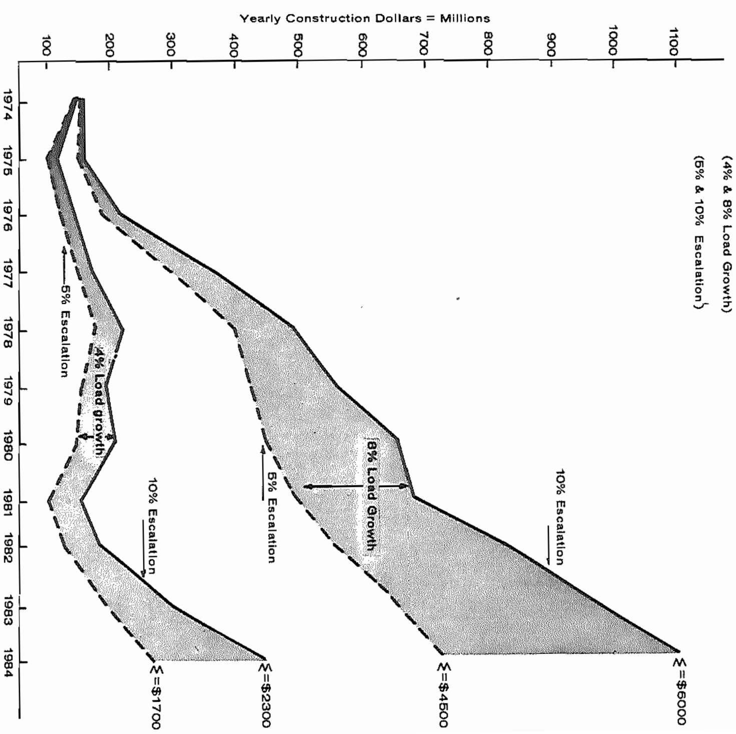
(Coal in Millions of Tons)

	Industry Plan	EPA Plan
No Conversions		
Total Coal	584	583
Low Sulfur[1] Coal	105	173
Required Scrubber Capacity	38,015	93,421
FEA Recommended Conversions		
Total Coal	622	622
Low Sulfur[1] Coal	105	173
Required Scrubber Capacity	38,015	116,480
All Plant Convert		
Total Coal	922	909
Low Sulfur[1] Coal	184	311
Required Scrubber Capacity	42,992	164,706

[1]Less than 1% sulfur.

Figure 1

NEES' 10-YEAR CONSTRUCTION FORECAST



get much attention — it is labor intensive. The British have learned, to their sorrow, of the control exerted by the coal miners. In fact, some of you may have visited London during a period when the British were forced into blackouts due to lack of coal brought about by labor strikes.

The problems of handling coal ash are often overlooked and probably deserve more attention than we have given them today. Dumping fly ash at sea is an obvious solution, but one that is quickly vetoed by environmental authorities. Utilization of coal ash in building materials and road construction is meeting with increasing resistance. In fact, in Massachusetts, fly ash is now considered a refuse material and can only be placed in approved landfill operations. These are very difficult to find and increasingly expensive.

In conclusion, there are two myths about utilities that I would like to clear up. The first of these concerns our supposed penchant for nuclear power. I am afraid many people think that the electric utility industry in New England is wedded to nuclear power and refuses to consider other alternatives. This is not the case. Nuclear power is more capital intensive than coal and/or oil-fired facilities. My life as a utility executive would be much easier if our industry could plan on less capital intensive sources of base-load generation. As previous speakers have indicated, the attraction of capital to the energy industries of New England is a critical problem. The reason the utility industry reluctantly selects nuclear for base-load generation is simple. It is the lowest-cost source of electric power of all the options that are available to us. In fact, nuclear power offers the only energy solution that will bring New England's electric energy costs into a competitive position with other parts of our country.

The second myth that I would like to correct concerns growth. I fear many people believe that electric utility executives strongly favor electric energy growth and only reluctantly pursue conservation of energy. This is not the case. Figure I will, I hope, convince you that rapid growth brings real problems to our industry. The bottom band on this figure indicates NEES' annual construction budget with 4 percent load growth. It implies annual expenditures of $170-230 million per year over the next 10 years. The upper band shows the same information if consumption grows at an 8 percent rate. With 5 percent inflation annual capital needs would average $450 million, with 10 percent inflation, $600 million. Obviously if we grow at 4 percent our capital needs are significantly lower than at 8 percent and we will escape the capital attraction problems associated with the difference.

In addition, every time we add a new unit of capacity, we raise our average costs. Unfortunately, the economies of scale that were so significant through the 1960s no longer offset the impact of inflation. This means the faster we grow, the higher our average costs and the greater the need for rate increases. In addition, the faster we grow, the more common equity we have to sell. And, unfortunately, if the above points were not enough (and they are), our common equity is now selling below book

value. Selling below book value results in a reduction in the earnings potential of existing shares. Under this situation everybody loses. The customers lose because the faster the growth the faster the rates go up, and the investors lose because the faster the growth the faster earnings decline.

Georges Bank Petroleum and New England Regional Income

J.W. Devanney III*

I. Introduction

There is a genuine possibility of petroleum production on the New England Continental Shelf. The last Department of Interior schedule I saw called for a Georges Bank lease sale in the summer of 1976. If this schedule is maintained, by mid-1977 we should have a pretty good idea of the scale of production possible for the Georges Bank, if any. Actual production could begin by 1980 with production peaking in the mid-eighties and early nineties.

Contemplating such a development, an obvious, if not particularly edifying question is: What's in it for us? What will be the economic impact on New England of Georges Bank petroleum? In order to answer this question, we must first ask ourselves: What's in it for the Nation? Having answered this question, we can then ask ourselves what portion of any increase in national income is likely to accrue to New England.

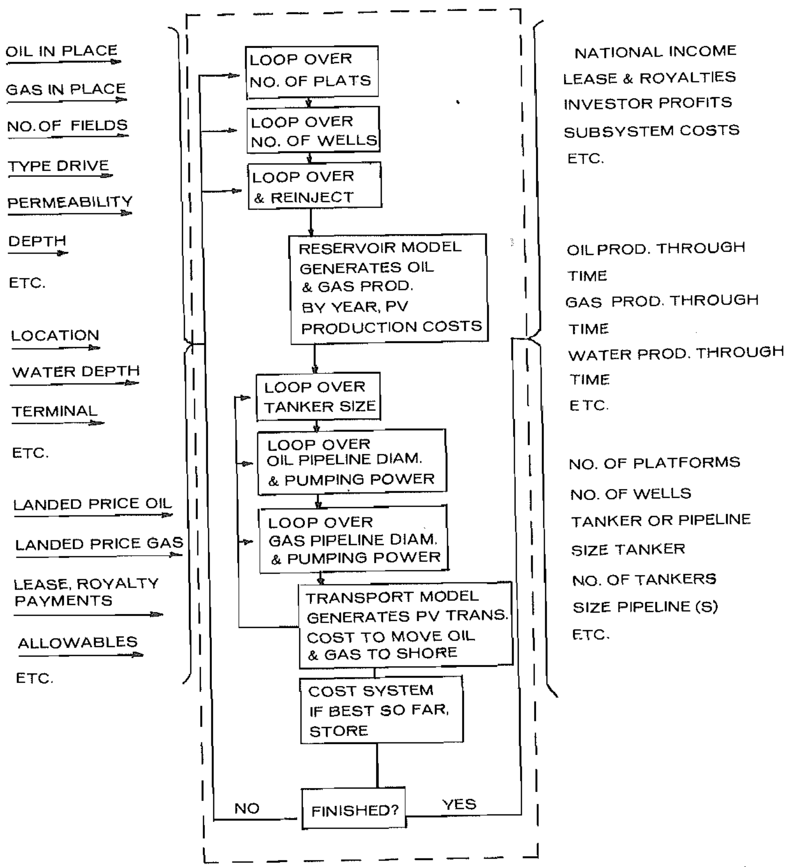
II. The Impact of Georges Bank Oil on National Income

With respect to "what's in it for the Nation," the answer is — possibly a great deal. As part of our work on offshore oil at MIT, we have constructed a computer program known as the Offshore Petroleum Development Model. The program, outlined in Figure 1, takes as input a number of geological variables describing a hypothetical offshore find (amount of oil in place, amount of gas in place, type of reservoir drive, permeability, viscosity, pay thickness, etc.). The input also includes variables describing the location of the find such as distance to shore, water depth over the field, and platform design wave height. Finally, the user of this program must also specify a number of financial and regulatory variables including the landed price of oil and gas, cost of capital, lease payment and royalty laws, and allowables.

*Associate Professor, Department of Ocean Engineering at the Massachusetts Institute of Technology. He was the Project Director of the Georges Bank Petroleum Study and Co-Director of the Atlantic Gulf of Alaska O.C.S. Study for the Council on Environmental Quality. He is author of *Marine Decisions Under Uncertainty* and the President of Martingale, Inc., a consulting firm.

Figure 1

OFFSHORE DEVELOPMENT PROGRAM



The heart of the program is a reservoir model which simulates the stipulated reservoir's physical response by year to a particular development strategy. The computer examines a number of such production strategies, varying number of platforms and wells installed, and the amount of reinjection. For each such production strategy, the computer examines a number of different transportation systems for bringing the resulting oil and gas ashore.

The program selects that combination of production strategy (number of platforms, number of wells, amount of reinjection) and that transportation system (size of tankers and diameter of oil pipeline and/or diameter of gas pipeline) which maximizes the investor's present value after-tax profits. The output from the Offshore Development Model also includes the resulting oil and gas production through time, and the time stream of financial payments to public bodies and suppliers.

One can learn a number of things from such a model but the single most important result to date is illustrated by Figure 2. This figure shows the model's estimates of the unit resource cost of landing Georges Bank oil for a range of find sizes and types. The *unit resource cost* is the per barrel loss in national income associated with diverting the men, steel, energy, and capital required to produce this oil from alternate employment. It is an estimate of the national income these resources could have produced elsewhere if they were not used in producing this oil. Assuming reasonably full employment in the supplier markets, this loss in national income is approximated by the pre-tax, pre-lease bid and royalty, present valued cost to the developer, placed on a unit of output basis.

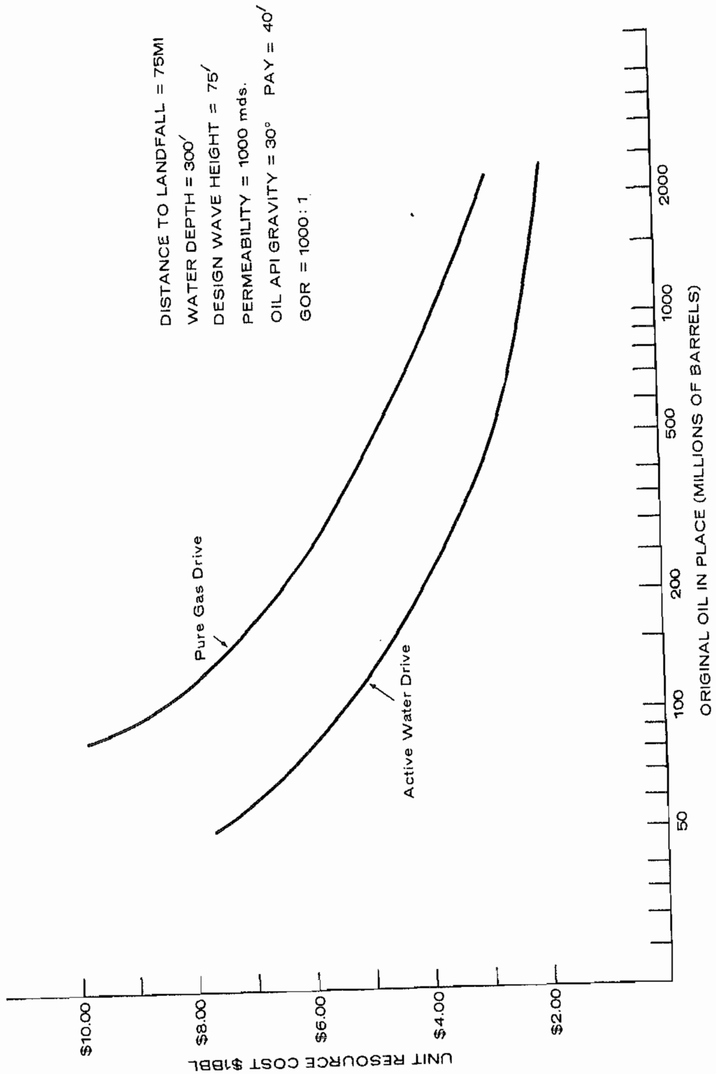
According to our analyses, the unit resource cost to the Nation depends sharply on the size of the find. Further, for large finds, this unit resource cost can be as low as $2.00 or $3.00 per barrel; far below the current cost to the Nation of landed OPEC crude — about $13.00 per barrel.

In other words, if we find a lot of oil on the Georges Bank, say one billion barrels recoverable, the present value increase in real national income could be as much as $10.00 per barrel or $5-$10 billion in aggregate.[1] Such numbers take on added significance when it is realized that almost all petroleum both in this country and abroad is produced from a very few, extremely large fields. Worldwide 65 percent of all petroleum reserves is contained in less than 50 fields. Some 50,000 oil fields have been found in the United States. However, the top 250 fields contain 65 percent of all remaining reserves. The top 11 fields, shown in Table 1, contain close to 50 percent of remaining reserves and the single largest field, Prudhoe Bay, 25 percent.

[1]These numbers and all the subsequent analysis assume that the OPEC cartel is not broken. If it is, and c.i.f. OPEC crude prices fall to the long-run cost of production and transport, about $2.50 per barrel, then even a very large find on the Georges Bank will be a marginal investment from the point of view of the country.

Figure 2

UNIT RESOURCE COST AS A FUNCTION OF SIZE OF FIND*



*Unit cost based on primary recovery only

Table 1

DOMESTIC SUPER GIANTS
(Reserves in Millions of Barrels)

Field	Discovery Date	O&GJ Reserves
Prudhoe Bay	1968	9,600[1]
East Texas	1930	1,800
Yates	1926	1,000
Elk Hills	1919	1,000
Kern River	1899	850
Wilmington	1932	700
Wasson	1936	630
Kelly-Snyder	1948	500
Midway Sunset	1894	420
Hawkins	1940	300
West Ranch	1938	300
		17,000
Santa Ynez[2]		2,000-3,000

[1]Unofficial reports set recoverables at 12.5 billion.

[2]Not yet entered in reserves estimates.

The reason for this top-heavy distribution is simple. The range of field sizes in terms of original oil in place runs from over 100 billion barrels to a few hundred thousand barrels or less — over five orders of magnitude. In short, one very large find can be worth literally thousands of small finds. Further it is in the nature of petroleum that, with high probability, either you find a lot or you find nil. If conditions in a basin are favorable, a lot of oil will be formed and trapped. If not, little or none.

This should be kept in mind in interpreting the average "expected" find estimates which are currently being tossed around for the Atlantic outer continental shelf (O.C.S.). One hears estimates of 250 million barrels, 500 million barrels average "expected" recoverable for the Georges Bank. In my opinion these numbers are next to meaningless, not only because they are based on very little information and discredited estimation methods, but also because, whatever happens, it is extremely unlikely to be the average. In my layman's opinion, there is a better than even chance that we will find no commercial petroleum on the Georges Bank. However, if we do find commercial oil, we will find a lot, that is quantities well in excess of a billion barrels.

With this in mind and examining results such as Figure 2, I conclude that if Georges Bank petroleum is ever produced, it is quite likely to be landed at a resource cost well below, as much as $10.00 per barrel below, current OPEC prices.

If this is the case, the obvious next question is: Where will the resulting multi-billion dollar increase in national income associated with such oil show up? It has sometimes been alleged that in the absence of bonus bids, royalties, etc., the savings associated with domestic O.C.S. oil will be passed on to the consumer in the form of lower prices. In this case, the increases in national income would automatically accrue to the oil-consuming public.

However, in the absence of direct price regulation, this simply will not happen. Even assuming price competition among the O.C.S. leaseholders, the landed price of O.C.S. oil will not drop below the landed price of OPEC crude unless there is enough domestic production to push all foreign oil off the U.S. market — an extremely unlikely event.

The argument for this statement is as follows. Assuming competition, the landed price of O.C.S. oil will be determined by supply and demand. The supply curve of crude to the United States looks something like the line AA in Figure 3. The curved portion of that line represents domestic supply as a function of unit resource cost to the Nation. As indicated, some of this crude is quite cheap. The horizontal portion of that line represents the supply curve for imported crude. The reason why this portion of the curve is essentially horizontal is that the cartel of exporting countries, under OPEC leadership, attempts to adjust their f.o.b. prices such that from the U.S. point of view, it is as expensive to import from one source as from another. Essentially, once you meet the OPEC price, you can buy as much oil at that price as you want.[2]

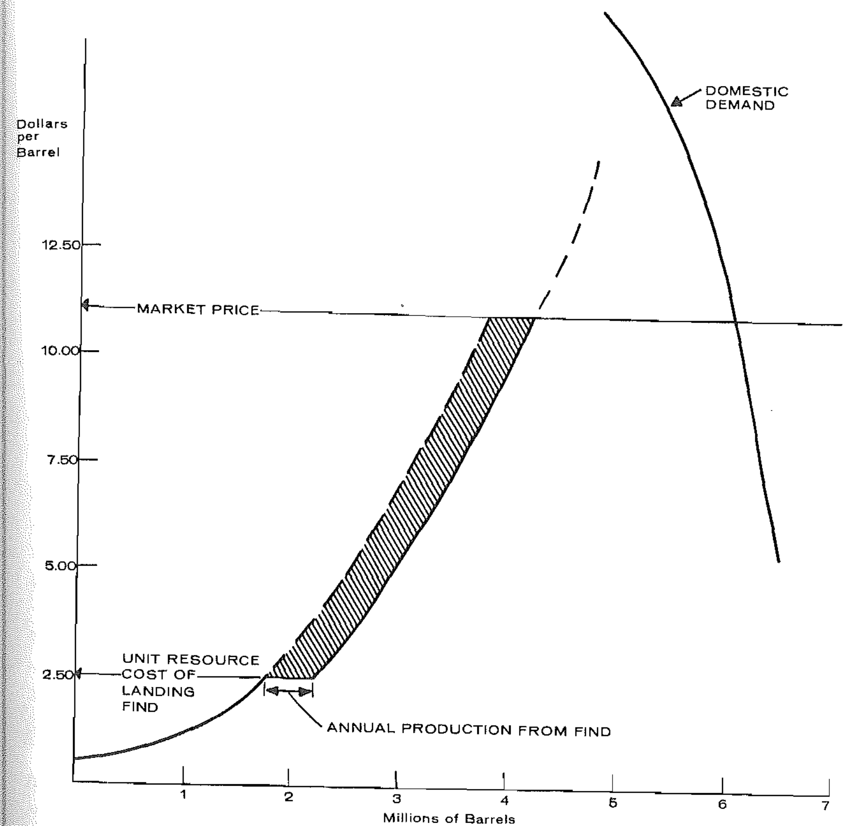
At present, the United States is importing about 2.25 billion barrels per year, about 38 percent of consumption. Unless domestic production increases to force all this oil off the market, the demand curve will intersect the supply on the horizontal portion of the supply curve. The vertical level of this intersection, the c.i.f. OPEC price, will determine the domestic price of crude. Price regulation aside, no domestic producer will sell his oil for less than the landed price of foreign crude, for he knows that there are domestic buyers who are paying this price to whom he can sell his oil.

Given this situation, let us consider what will happen if we make a large find on the O.C.S. As we have seen, the landed resource cost of such oil can be less than $3.00 per barrel. The effect of such a find on the supply curve of domestic oil is shown by the line BB in Figure 3. The find is equivalent to a rightward shift of the supply curve at the unit resource cost of landing this find — $2.50 per barrel in the sketch. The amount of the shift is equal to the annual production from the find. Note that unless the amount of the shift is sufficient to push all foreign oil off the domestic

[2]This is not the case during actual embargoes. From time to time, the exporter cartel may call an embargo to raise the overall level of the horizontal portion of the curve. However, it is in the interest of the cartel to keep these embargoes relatively short; as soon as the price rise has been effected, the embargo is lifted and once again one can purchase as much crude as one wants at the new price.

Figure 3

SKETCH OF U.S. OIL SUPPY AND DEMAND WITH LARGE NEW FIND



market, there will be no change in price, for the intersection of the demand curve and supply curve is still at the same horizontal level. *Under competition, market price will not be affected by any individual O.C.S. find unless the aggregate of such finds pushes all foreign oil off the U.S. market.* To the extent that the relevant markets are not completely competitive this conclusion holds a fortiori.

The fact that price is not affected does not mean that there has been no increase in national income. In fact, the annual increase in national income associated with the hypothetical find sketched in Figure 3 is the hatched area in this figure. This is the difference between the unit cost to the Nation of imported crude and the unit resource cost of the O.C.S. find multiplied by the amount of the find. In the situation shown, we are replacing $11.00 foreign crude with $2.50 domestic crude for a net gain in national income of $8.50 per barrel.

The hatched area, the national gravy if you like, is known as the *economic rent* associated with the find. This economic rent will be split between the Federal taxpayer and the investor in the development. The former will see lease payments, royalties, and income taxes which would not occur if the resource were not developed. Either his Federal taxes will be less than they otherwise would be or he will receive more public resources for the same taxes. The investor will see profits in excess of what he would have achieved without the development. Here I am using profits in a restricted sense to mean profits above and beyond the normal return to capital which the investor could earn elsewhere, for this normal return to capital has been included in the unit resource cost by the present value process.

The actual split between the taxpayer and the developer will depend on the type and effectiveness of the Federal O.C.S. management policy being employed. On the one extreme, simple homesteading and no income taxes, the entire increase in national income, all the economic rent would go to the developer in the form of excess profits. The original British system approximated this extreme. On the other extreme are systems in which the developer is forced to bid away all or almost all the excess profits in the form of lease payments, royalties, and taxes, in which case all the economic rent would accrue to the public. The present Norwegian system may be approaching this extreme.

From the point of view of any individual American, this split between the developer and the taxpayer should be a matter of some interest especially since Congress is currently considering dismantling a system which, while far from perfect, appears to have directed the bulk of the economic rent associated with O.C.S. oil to the taxpayer.[3] However, this is not the subject of today's discussion; and paradoxically, how the split comes out may not be too critical from the point of view of total New England regional income. This is the subject of the next section.

[3]For a discussion of this issue, see: Devanney, "The OCS Petroleum Pie," *MIT Sea Grant Report,* MITSE 75-10, Feb. 1975.

III. New England Regional Income

There are five ways that offshore oil could affect real New England income:

1) by changing the real price New England consumers pay for petroleum,

2) by reducing New England's Federal tax burden or increasing the profits of New England investors in offshore development,

3) by reducing regional (state and local) taxes for the same level of public services,

4) by increasing the real earnings of New Englanders employed by the petroleum development,

5) through the *net* effect of respending of any of the above four increases in regional income.

The only reason for laying out this obvious list is that most studies of regional income concentrate entirely on one or two of the above aspects of the problem to the exclusion of the others. Often they grossly exaggerate the aspect they have chosen to examine while missing completely other impacts which in reality are likely to be larger.

Regional Petroleum Price Changes

We have already argued that, however cheap the offshore petroleum actually is, as long as there are no price controls this petroleum will have no effect on market prices. It now appears reasonably certain that there will be no price control on "new" oil such as Georges Bank production. In fact, the President is going in the other direction and relaxing "old" oil price controls. Therefore, I do not believe that price control of Georges Bank oil is a realistic possibility.

For historic, political reasons, the situation with respect to Georges Bank gas is considerably less clear. Our analysis of hypothetical gas finds on the Georges Bank indicates that nonassociated gas can be landed from a large find for less than 60¢/Mcf while the marginal resource cost of landing associated gas can be less than 30¢/Mcf. Once again these resource costs are far below the $2.00/Mcf and higher than New Englanders are paying on the margin for foreign gas.

Continued, if somewhat relaxed, gas price control is a real possibility. Assuming such price control, gas will continue to be rationed in New England. At the controlled price, more gas will be demanded than supplied. In this case, the increase in real regional income associated with a gas find will be the consumer's surplus associated with the new gas at current New England prices plus any difference between the present regional price of gas and the regulated landed price of Georges Bank gas. Given a large gas find, the increase in regional income could be quite considerable. If we discover ten trillion cubic feet of gas (a large find) under reasonably strict price control, the increase in real consumer income could easily be $5 billion present value. Undoubtedly a portion of such gas would be supplied to the New York market but New England consumers could reasonably expect to see 25 percent or more of this increase.

As we shall see, the resulting increase in real New England income of a billion dollars or more present value completely overwhelms in magnitude the possible increases in regional income due to jobs and regional taxes.[4]

Reduction in Federal Taxes for the Same Level of Federal Public Service and/or Increase in Profits to New England Investors

As argued earlier, the great bulk of any increase in national income due to offshore oil will be somehow split between the developers in the form of profits above the normal return to capital and the Federal taxpayer in the form of lease payments, royalties and taxes which would not occur without the development. Contrary opinions held in some circles, notwithstanding, New Englanders are Americans, and as such can be both offshore investors and Federal taxpayers.

New England represents about 5 percent of the country's population and of its wealth. If we assume that the benefits to the Federal taxpayer of offshore revenues are spread evenly over the country and that New England investors participate in offshore ventures in a manner roughly proportional to their overall share of the country's wealth, then about 5 percent of the economic rent associated with a find would accrue to the region. For a one billion barrel recoverable find, this share could amount to $500 million at present value. For a 100 million barrel find, the share will likely be negligible for the resource cost of the landed oil from such a discovery is probably close to the current market price.

Notice that the 5 percent to New England conclusion holds no matter what the split is between the investor and the Federal taxpayer, provided only that New Englanders share in the investment and in Federal taxes in similar proportions.

The actual split of the economic rent between investor and Federal taxpayer is unlikely to have a critical effect on *total* regional income. It will, however, determine which groups in New England are the primary beneficiaries of the increase in regional wealth. If the investors end up

[4]This does not necessarily imply that New England should lobby for continued gas price control. From the point of view of the region, gas price decontrol involves the following pluses and minuses.

Pluses:
1) increase in consumers' surplus of those New Englanders who would receive any additional domestic gas brought into the region as a result of decontrol,
2) increases in New England investor and Federal taxpayer income associated with higher pre-tax gas producer profits.

Minuses:
1) loss in real income to current New England gas consumers associated with the higher price,
2) loss in real income associated with the differences in the prices of any offshore gas discovered with and without control.
We have not analyzed this trade-off.

keeping most of the rent, then relatively wealthy New Englanders will get the lion's share. If the Federal Government takes the bulk of the economic rent and spends this additional income on, say, welfare programs, then poor New Englanders will be the principal beneficiaries.

In any case, New England's share of the national economic rent associated with an oil find is likely to be roughly 5 percent of the total. The resulting increase in regional income may well be the second largest regional impact, following the benefits from a large gas find with price controls. In present value terms, this increase in regional income resulting from a large find could be several hundred million dollars.

Local Employment

We now turn to the much ballyhooed regional employment and local tax impact. In addressing this impact, the first notion we have to disabuse ourselves of is any necessary connection between Georges Bank oil and regional refining. According to Section I, if oil is produced from the Georges Bank, it is likely to have a resource cost more than $5.00 per barrel less than current market price. It will cost about 25¢ per barrel to move Georges Bank oil to New England in quantity via pipeline. It will cost about 60¢ per barrel to take this oil to the mid-Atlantic via tanker. This differential is not particularly impressive. A developer of a large find would have no problem with refining his oil in the mid-Atlantic.[5]

For a small find, which would be landed by tanker in any case, this argument holds a fortiori for the differential in tanker cost from Georges Bank to New England and from Georges Bank to the mid-Atlantic is less than 15¢/barrel.

Further, our simulation of hypothetical reservoir production histories indicates that even a very large, two billion barrel recoverable find could supply the entire 1.2 million barrel per day New England market for at most two or three peak production years. This implies that either the bulk of Georges Bank crude during peak production years will have to go to non-New England refineries or that any New England refineries will have to be prepared to refine non-Georges Bank crude for the greater portion of their lives.

Right now domestic refineries are operating well below capacity. In general domestic refineries have found it is cheaper and a lot less troublesome to expand existing plants rather than invest in entirely new grassroot facilities. There is great uncertainty as to what the country's future crude and product import policy will be. Finally, if the OPEC countries carry out their announced plans of drastically expanding refining capacity, even the long term looks bleak for expansion of domestic refining.

[5]A corollary to this is that even if the region wanted to, New England could not prevent development on the Georges Bank by denying the oil a landing place on the New England coast.

In summary, New England refining and Georges Bank oil can be regarded as largely independent issues. If New England refining makes sense from the point of view of the region, it makes sense without Georges Bank crude. If New England refining doesn't make sense, it doesn't make sense with Georges Bank oil. In this situation it is entirely misleading to credit (debit) any changes in New England income due to regional refining to offshore oil. Therefore, we can concentrate solely on the offshore oil support activities.

Let's begin with direct support. The magnitude of direct-support activities is considerably smaller than sometimes suggested. The exploration phase is likely to begin with at most two or three rigs. If, and only if, the results are favorable, this could rise to a maximum of four to six rigs. The exploratory drilling phase will last perhaps five years — a good deal less if the first wells are discouraging.

Our reservoir simulations indicate that even an extremely large multi-billion barrel find could be produced from no more than 30 platforms representing some 500 wells.[6] Not all these platforms would be manned. These platforms would be erected over a five- or six-year period.

So let's assume the maximum as has been done in Table 2. Each exploratory rig will require a stand-by boat plus 12 supply boat movements per month. Each platform will require about 30 supply boat movements per month during the two-year drilling phase dropping to less than four per month afterwards.

If the oil is piped to New England, main transmission-line laying will be accomplished in one, or at most two, summers. In any case, there will be some gathering network work. Pipelaying generates about 80 boat movements per month. Industry experience indicates that a single shoreside berth can support about 30 boat movements.[7] Putting these numbers together leads to the totals in Table 2. Note that even under the assumption of a massive find, less than 20 shoreside berths will be required and at most some 50 nonpipelaying vessels. A generous rule of thumb is five shoreside acres per berth. Many places, e.g., Aberdeen, get by with much less. Assuming five acres per berth, the full shoreside requirements could fit within the South Boston Navy Base with plenty of room to spare or on a small corner of the Newport Navy Base. We repeat these are maximums. The support base for Ekofisk, a 2.5 billion barrel find in Stavanger, contains less than 10 acres. The Scottish North Sea, in excess of 15 billion barrels, is largely supported from less than 50 acres at Peterhead.

A manpower schedule consistent with the above hypotheses is shown in Table 3. The percentages of New Englander participation in this employment are frankly guesses which seem reasonable to me based on my

[6]The Forties Field, a two billion barrel find in the North Sea, will be produced from four platforms. This is typical of North Sea practice.

[7]N. Trimble, "How Many Supply Bases Does Scotland Need?" *Offshore Services,* November 1974.

Table 2

HYPOTHETICAL SCENARIO — MULTI-BILLION BARREL FIND ON THE GEORGES BANK

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Number of Expl. Rigs	2	4	6	6	4	2	0	—	—	—	—
Number of Platforms			5	10	15	20	25	30	—	—	—
Number of Vessels to Support Expl. Rigs	4	8	12	12	8	4	0	—	—	—	—
(Vessel Movements per Month)	(24)	(48)	(60)	(60)	(48)	(0)	—	—	—	—	
Number of Vessels to Support Platform Installation			15	30	30	30	30	30	15	0	—
(Vessel Movements per Month)			(150)	(300)	(300)	(300)	(300)	(300)	(150)	(0)	—
Number of Vessels to Support Pipelaying			8	8		8		8			
(Vessel Movements per Month)			(80)	(80)		(80)		(80)			
Number of Vessels for Field Maintenance					2	5	7	10	12	15	—
(Vessel Movements per Month)					(20)	(50)	(70)	(100)	(120)	(150)	—
Total Number of Non-Pipelaying Vessels	4	8	35	50	40	49	37	40	27	15	—
Total Number of Vessel Movements per Month	(24)	(48)	(290)	(420)	(370)	(450)	(370)	(480)	(270)	(150)	—
Number of Berths Required	2	4	12	15	14	17	14	18	10	6	—

Table 3

MAN-POWER SCHEDULE FOR MULTI-BILLION BBL FIND SCENARIO

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Expl. Rig Crews	200	400	600	400	200	0	—	—	—	—	
(Likely N.E. Participation)	(nil)	(100)	(150)	(200)	(200)	(100)	(0)	—	—	—	—
Rig Support Vessels	40	80	120	120	80	40	0	—	—	—	
	(nil)	(30)	(60)	(90)	(70)	(40)	(0)	—	—	—	—
Platform Installation			500	1,000	1,000	1,000	1,000	1,000	1,000	500	0
			(200)	(500)	(600)	(700)	(700)	(700)	(700)	(450)	(0)
Vessels Supporting Platform Installation			150	300	300	300	300	300	300	150	0
			(100)	(250)	(300)	(300)	(300)	(300)	(300)	(150)	(0)
Pipelaying and Supporting Vessels			300	300		300		300			
			(nil)	(nil)		(nil)		(nil)			
Platform Maintenance and Supporting Vessels					170	350	520	600	870	1,050	1,050
					(120)	(250)	(450)	(500)	(800)	(1,000)	(1,000)
Shoreside Non-Management	20	40	120	200	200	250	250	250	150	60	60
	(20)	(40)	(120)	(200)	(200)	(250)	(250)	(250)	(150)	(60)	(60)
Total	260	520	1,890	2,520	2,200	2,250	2,100	2,450	2,350	1,750	1,110
Total New England	(20)	(170)	(620)	(1,250)	(1,300)	(1,450)	(1,700)	(1,750)	(1,950)	(1,650)	(1,060)

observations of the offshore industry in the Gulf and the North Sea. Local participation will be quite low in the very transient pipelaying and exploratory drilling activities, but can add up to the great bulk of the nonsupervisory jobs in production drilling, platform maintenance and nonpipelaying vessel operation. Accepting for the moment my guesses, we find that even a relatively massive development on the Georges Bank will generate a peak of perhaps 2,000 jobs, with a permanent employment of about half that. The direct employment numbers are consistent with Grigalunas's excellent study.[8] In my opinion, they represent upper bounds.

The major indirect employment possibilities are:

1) rig and platform building;
2) supply boat building and maintenance;
3) driving/mud, chemicals, cement/helicopters/etc.;
4) oil transhipment terminal/gas treatment and pipeline.

I don't believe the specialist category (3) is worth worrying about. Unless the development is unusually long lived, these services will be provided by non-New Englanders. The aggregate numbers involved are not large. Finally, any New Englander who has the training and experience to handle this work will not be unemployed.

Unlike Grigalunas, I am not sanguine about the possibilities of rig- and platform-building in New England. New England is at a competititve disadvantage with respect to the South in weather and labor costs. Further, the Gulf is beginning to play out, in which case there is likely to be excess already established rig- and platform-building capacity there. Finally, the world's shipyards are entering a superslump which is likely to last three or more years. These yards are therefore turning to rig building. We recently made a trip to the Gulf and talked to about a dozen rig and platform builders about their using the Boston Navy Base. To a man they were completely disinterested. Discoveries on the Georges Bank offer no competitive advantage to a rig builder. Builders of these mobile investments must be prepared to compete with the world. Therefore, any New England rig-building activity cannot depend on nor be credited to a Georges Bank development. A Georges Bank find would offer some cushion to a local platform builder. Towing costs from the Gulf will be about $750,000 higher than from New England. However, this amounts to less than 15 percent of the delivered cost of the platform and it is not at all clear that a new, cold weather yard could operate on this 15 percent as compared with established, warm weather facilities. Further, a regional yard will have much less than a 15 percent cushion over already planned expansions of rig and platform building in the mid-Atlantic. Finally, the Georges Bank market will most likely be limited to 20 or fewer platforms. All in all, not a particularly promising situation. I don't believe there will be any offshore platforms built in New England as a result of a Georges Bank find.

[8]T. Grigalunas, "Offshore Petroleum and New England," University of Rhode Island, Marine Technical Report No. 37, 1975.

Supply vessel building suffers from the same problems as rig building, although weather is not nearly as important for covered construction. More to the point, supply boats are completely mobile. Therefore, a find on Georges Bank will offer no competitive advantage to local builders. If a local supply boat builder can compete for contracts with a Georges Bank development, then it will be able to compete for contracts without such a development (as Blount has been able to do occasionally). Therefore, supply boat building activity cannot be credited to a Georges Bank find.

Supply boat maintenance is a different story. Supply boats operating on the Georges Bank will be maintained locally to keep the time out of service down. A large find on the Georges Bank will undoubtedly result in the installation of a supply boat maintenance yard, (or what is the same thing, continued existence of one of the local repair yards which would otherwise go under). However, the numbers are not large. Noncrew maintenance of a 50 boat fleet will require fewer than 150 men per year.

This leaves shoreside oil terminal/gas treatment and pipeline facilities. If the oil is brought ashore to New England and then shipped out, construction of a transhipment terminal will be required. This would be approximately a $20 million project involving perhaps 1,500 man-years on construction. Permanent employment would be less than 50. I regard this as an unlikely prospect. If the crude is not to be refined in New England, it will be cheaper to provide offshore storage and tanker loading facilities than to pipe it ashore and then load it.

Shoreside gas treatment plant and supporting pipelines is a more likely possibility. A very large gas find could result in several thousand man-years for treatment plant construction and perhaps another 1,000 man-years to connect the plant to the existing gas grid. This would be very short-term employment. The permanent effect on regional employment would likely be negative as the additional gas would supplant more labor intensive sources of energy, such as oil presently being handled by barge and truck within the region.

Therefore, respending effects aside, I am prepared to go with the figures of Table 3 plus perhaps 3,000 man-years, expended over two years, for gas treatment and pipelines in the case of a large gas find as an upper bound on regional employment associated with Georges Bank petroleum. To put these figures into context, the Boston Navy Base shutdown represented a gross loss of 5,000 jobs to the region. There are currently 650,000 people unemployed in New England, 200,000 in eastern Massachusetts and Rhode Island alone. Even a massive find on the Georges Bank is equivalent only to a good-sized but not particularly large industry entering the region.

The Net Effect of Offshore Development Jobs on Regional Income

To me the interesting question from the region's point of view is not how many people will work in offshore oil, but rather what the increase

will be in New England wealth as a result of this employment. The change in regional income due to offshore oil depends critically on what the regional resource employed would be earning without the development. If we had a full employment situation in the region, then the fact that a New Englander is earning $6.00 per hour on shore means very little for he could be earning $6.00 per hour doing something else. Under full employment no portion of the offshore industry's payrolls could be credited to New England income. At the other extreme, if we had complete unemployment, in which case this same New Englander would be on welfare, then the entire difference between his gross earnings and his Federal welfare would be a net increase in the real wealth of the region. Notice it is the employment opportunities of the actual people employed that count.

Currently, of course, we have rather severe unemployment in the region, especially in the Rhode Island-southeastern Massachusetts area. Therefore, despite the fact that the offshore development will undoubtedly hire the most easily employed — young, mobile males with at least a high school education and perhaps some vocational skills — I think it is currently fair to credit the development with the bulk of at least the short-term New England payroll net of Federal welfare. If we had full or close to full employment, this procedure would grossly overstate the impact of offshore oil on regional income through employment effects.

At 10 percent real, the present value of New England employment associated with Table 3 is about 9,000 man-years. Generously assuming a differential of $10,000 per man-year between gross earnings and Federal welfare payments, the present value of the increase in regional income associated with this employment would be $90 million. Construction of a large gas treatment plant and connecting pipelines might add 20 percent to these figures.

In other words, under the twin assumptions of a relatively massive development and severe regional unemployment, the increase in New England real income associated with offshore oil initial employment might be as high as about $100 million at present value. Reductions in the assumed size of the find on improvements in the region's employment situation would result in sharp reductions in this estimate.

Local Taxes

On the basis of estimated property evaluations, Grigalunas has estimated that onshore support facilities associated with a large find will pay as much as $1 million per year in property taxes. At 10 percent for 25 years, this would result in gross revenues of about $10 million at present value. It is quite likely that actual revenues will be less as the various states and towns bid against each other for the facility by offering tax abatements, holidays, etc. This process appears already to have started in Rhode Island.

Whatever the gross revenues are, they must be netted by the cost of any additional public services required by the facilities (sewers, roads, water, etc.). Both Texas and Louisiana have claimed that these deductions are larger than the revenues from offshore development for property and ad valorem state taxes cannot be assessed on the offshore facilities themselves. I happen to think that the Texas and Louisiana arguments overstate the case against offshore development but, in any event, the resulting numbers will be quite small, in the few millions of dollars at present value.

State corporate income taxation would offer a more interesting possibility *if it could be applied to the profits on production.* As mentioned earlier, depending on Federal lease management, these profits could run into billions of dollars. Four or five percent of such profits would represent a handsome sum indeed. Unfortunately, the production facilities will not be within state boundaries. Therefore, it seems to me that the states do not have any way of forcing the producing corporations to pay any state corporate income tax. I will assume they do not. It might be something for the states' lawyers to look into, or the region's congressional delegation to think about.

Respending Effects

A portion of the increases in regional income from categories 1 through 4 will be respent within the region. To the extent that there is unemployment of regional resources in these regional respending markets, this will result in differences in income to New Englanders supplying these goods and services. However, it is easy to overestimate the net effect of such respending on regional income. A large proportion of the direct increase in income will be respent outside the region. In a resource poor region like New England, a sizable proportion of the money spent within the region will be used to import extraregional resources. The regional input is mainly labor. Even under the severest conditions, not all this regional labor would otherwise be unemployed. In estimating changes in regional income associated with some development, it is important to work with the net multiplier and not with the gross multiplier.[9] The latter is a concept often misused by input-output enthusiasts.

I don't know what the net regional multiplier for offshore oil is. However, I would hazard a guess that, even in these times of severe regional unemployment, no more than one-third of the additional direct New England income would represent *increases* in income to New Englanders in the secondary markets. An infinite chain based on this guess would lead to a net regional multiplier of 1.5.

Whatever this net multiplier is, it should be applied to all the direct increases in regional income whether they be due to decreases in petroleum price, reduction in Federal taxation burden, increases in shareholder profits, or increases in take-home pay, provided only that the respending patterns are roughly similar.

[9]The gross multiplier is the total amount of economic activity required to support a unit of direct investment. The net multiplier deducts from this total the value of the output of these resources in alternative employment. It is the latter concept which is relevant to estimates of *changes* in regional income.

Table 4

ESTIMATES OF DIRECT CHANGES IN NEW ENGLAND INCOME DUE TO MULTI-BILLION BARREL FIND ON GEORGES BANK

	Present Value at 10% (Millions of $)	Present Value per Capita	Annual Over 20 Years per Capita
Difference in Gas Price and Gas Supply (Assumes Continued Price Control)	1,000	$ 80	$10
Region's Share of National Economic Rent Associated with Oil	500	40	5
Increase in Take-Home Pay of New Englanders Employed in Offshore Oil	100	10	2
Regional Taxes Net of Additional Cost of Regional Service	nil to 10	0	0
Total	1,600	130	20

IV. Summary

Table 4 summarizes our results. The table indicates estimates of the increase in New England income associated with a very large find on the Georges Bank. These numbers are obviously very rough, plus-or-minus-a-factor-of-two type figures. But even such rough estimates admit several obvious conclusions.

The first is that the savings associated with gas price control policies can be much larger than employment effects. The second is that, assuming a large oil find but little gas or gas price decontrol, the major effect on regional income will be a rather invisible one — a break on Federal taxes which would otherwise not occur coupled with an increase in the income of New Englanders who have invested in the oil industry.

Finally, and perhaps most importantly, even a large find on the Georges Bank will not be a panacea for the region's economic ills. The numbers shown are rough estimates of upper bounds. Even a massive development will employ at the very most 5,000 New Englanders and very likely many fewer. Currently regional unemployment is over 600,000; and it is not clear that all the offshore employment will be drawn from the ranks of the unemployed.

The second column puts our estimates on a per New Englander basis. The numbers shown represent the equivalent per capita increase in real wealth on a one-shot basis. The third column amortizes these increases over 20 years at 10 percent. According to our estimates, even a massive development will increase per capita income only by about $20 per year. Once again I repeat these are upper bounds. The actual amounts will almost certainly be less.

In short, offshore oil can, under very favorable circumstances, generate a rather tidy increase in regional income. However, the bulk of this increase will show up in unexpected, rather invisible forms. Finally, even in aggregate the possible amounts do not appear worth losing our collective heads over. Some deliberate, careful thought is still in order to insure that the region gets the best deal possible from offshore oil.

Discussion

Alex Steinbergh*

I would like to cover four points in my discussion. First, I will compare Professor Devanney's analysis with some of our own firm's forecasts for New England's onshore development impacts. Secondly, I will indicate what the pace of development is likely to be without new OCS legislation. Thirdly, I will discuss what I think will happen given the probability of new OCS legislation. Lastly, I will point out some of the things we in New England can do to prepare for Georges Bank development and maximize the benefits that Professor Devanney talks about.

Devanney's OCS Analysis

I feel that Professor Devanney has done an excellent job in assessing the regional benefits associated with Georges Bank oil and gas development, especially in focusing on the fact that the major benefits will be those associated with the feedback of economic rents into the region in the form of lower taxes and increased profits. One may criticize his failure to cover some of the potential environmental costs associated with OCS development, such as the potential losses associated with oil spills, onshore impacts of additional land requirements, and additional onshore air and water pollution. However, these impacts have been pretty well documented in a study of offshore development in the Atlantic Ocean that both MIT and Resource Planning Associates were associated with two years ago. The general conclusion reached by that study, and also recently by most responsible members of the environmental community, is that, on balance, oil and gas drilling do not have excessive environmental risks. Certainly, proper installation, offshore monitoring, and contingency plans can bring the risk down to acceptable limits. Similarly, we believe that the

*Principal and Senior Economist with Resource Planning Associates. He leads the firm's oil and gas practice area and has directed various projects in the areas of energy policy and environmental impact and strategy.

adverse onshore environmental impacts, although perhaps of more concern than the offshore impacts, can be controlled if state and local governments, as well as the Federal Government, have a say in the planning process and if enough funds are available to do this planning.

In planning for OCS development, the first, and perhaps most important, analysis to be done is a comprehensive benefit/cost study at both national and regional levels. I think Professor Devanney's paper provides a framework for such an analysis. Incidentally, I am not aware that the Bureau of Land Management (BLM), despite the millions of dollars it has invested in environmental impact studies in OCS regions around the country, has done a regional income analysis such as this for any individual sale. The massive finds that Professor Devanney has assumed to illustrate the maximum benefits to New England — 2 billion barrels of oil and 10 trillion cubic feet of gas — are certainly optimistic. The U.S. Geological Survey recently estimated between 2- and 4-billion barrels of oil and 5-14 trillion cubic feet in all the Atlantic coast OCS areas, including the Mid-Atlantic and South Atlantic regions as well as Georges Bank. However, I agree with Professor Devanney that if there is oil and gas, and if it is economical to recover it in large amounts, we ought to look at the impacts of large finds.

As far as gas is concerned, 10 trillion cubic feet would provide about 500 billion cubic feet a year for 20 years. This is approximately twice New England's current consumption level. Ten trillion cubic feet is about what BLM is now officially estimating in the Gulf of Alaska. In other words, Devanney's assumptions reflect a pretty big find. Professor Devanney assumes that it would be brought ashore for gas processing plant treatment and that there would probably be a reversal of the existing pipeline system in New England to pipe it towards New York, so that New England would be able to tap off the pipeline. The biggest area of controversy, of course, is the extent to which New England would be able to use this gas. On an economic basis, OCS natural gas would seem to have many advantages. However, the economic benefits to be derived from this gas depend heavily on what the Federal Power Commission has to say about user allocation priorities.

In general, however, Professor Devanney's estimates of both direct and indirect benefits, totaling some $2-3 billion on a present value basis, are similar to our own forecasts, although we have not assumed deregulation and therefore have lower benefits for natural gas. We have estimated the share of the rent coming to New England as about $375 million on a present value basis, and we have slightly higher estimates of the benefits of new jobs to New Englanders. Even so, assuming that there will be no new refineries, we can expect at most 5,000-6,000 new jobs for New Englanders, with perhaps another 6,000-8,000 new jobs for people coming into the region, and perhaps 15,000-20,000 new residents for New England. We feel that this is still a relatively significant net benefit to the region, but not one to get overly excited about in the existing unemployment situation.

Pace of Development Without New OCS Legislation

Given existing OCS legislation and assuming that OCS development will proceed, how will this development be carried out? We feel it will be very slow. Government participation in OCS development is currently controlled by two Acts. The first is the OCS Land Act of 1953, which is administered through the Bureau of Land Management and the U.S. Geological Survey (USGS). This Act has worked remarkably well in the Gulf, and provides the Department of the Interior with the powers to lease offshore lands, and regulate offshore production and the pipeline to shore. The second major Act, the Coastal Zone Management Act of 1972, which is administered by the Department of Commerce, provides a framework for onshore planning through grants to state coastal land management offices to develop land-use plans. However, the lack of coordination between the two Acts constitutes a major problem. Add to this the fact that the Federal Energy Administration is promoting energy development in OCS lands and the EPA and Council on Environmental Quality (CEQ) are resisting development without adequate environmental controls and you begin to see the regulatory environment in which OCS oil and gas development is currently operating. The Department of the Interior is trying. It has developed a number of regulations to improve these decision procedures and get the states more involved. However, BLM has just begun to scratch the surface and much more advanced planning is needed.

To illustrate the problems, let me give a quick review of the proposed procedure for the development of Georges Bank, the schedule for which incidentally is somewhat similar to those in other OCS regions that are to be developed concurrently. In June of this year, BLM invited companies to nominate parcels to be offered for lease. On August 18, the oil companies nominated almost 2,000 tracts totaling 11 million acres for the August 1976 proposed lease sale. The tracts are 25 to 100 miles offshore, the closest one being 25 miles off Nantucket. The largest interest was in the southern part of Georges Bank off Massachusetts and Rhode Island. Certain negative nominations were submitted by coastal states, fishing interests, public works, etc. In October, BLM will probably narrow down the tracts left in process to around 3-4 million acres. This estimate is based on what happened in the Baltimore Canyon Lease Sale, where about 3 million acres were nominated and less than 1 million acres were tentatively selected for resale. The Interior will start working on its draft Environmental Impact Statement (EIS) and will publish it in January. There will be public hearings in March and, if everything goes smoothly, the EIS will come out in June and by next summer we will have a lease sale.

However, in actuality we can expect extensive delays in this schedule. Currently, there are two developments that I think show there will be delays. First, before the Interior is allowed to lease any of the frontier regions, it must issue a final EIS on its entire leasing program. This has been held up for a number of reasons, not the least of which were the problems associated with the nomination and resignation of Secretary

Hathaway. But basically the EIS will probably be delayed another two to three months to reflect many of the concerns of all the coastal states. Secondly, the California sale, which was scheduled for November, and the Gulf of Alaska sale, which is now scheduled for December, will probably also be delayed. Both California and Alaska through Governors Brown and Hammond have threatened suits, and we feel this pattern will continue unless there is new legislation.

In other words, BLM is running behind schedule. Why? For two reasons. The first, I think, is just bureaucratic rigidity and the limitations imposed by existing legislation, which make it difficult for BLM to adequately address the onshore impacts that are the greatest concern to the states. BLM has not done a careful cost/benefit analysis for any of the regions. This is an optional procedure in the National Environmental Protection Act (NEPA) procedure that BLM has opted not to follow which I think is a mistake. I think an analysis similar to Professor Devanney's should have been done for all of the regions.

The second reason is that the states in the meantime are embarking on their merry way through the coastal zone management program grants and some state funding is allocated to preparing for OCS development. Most of these states have had little experience with the whole oil and gas exploration, development, and production process, which Professor Devanney has described, and there has simply been too little funding and too little time to become aware of what they need to plan for.

The most significant thing that BLM has done was announced in the last month — the establishment of the requirements for lease development plans. Under these regulations, lessees of the oil companies would be required to submit development plans to the USGS supervisor prior to the development phase. The governors of the coastal states would have a 60-day comment period — no veto, but a comment period — and the USGS supervisor would have the responsibility for saying whether the oil companies could go ahead. These regulations are still in the process of being finalized, but if they remain unchanged, the oil companies would provide the states with considerable information concerning not only the facilities but the prospective onshore and environmental impacts. EPA has reviewed the Interior's plan and wants even greater detail. They want to require a full environmental impact statement before going into the development stage, and they want some recourse if the governor of a state still feels that the development plan is inaccurate and inconsistent with his coastal zone management plan.

So you see BLM is operating in a very difficult environment and I think substantial delays will occur unless it is changed. The real change, I think, must be legislation.

Possible Effects of New OCS Legislation

Right now, two of the foremost requirements of OCS development that require regional planning are included in parts of the two Senate bills, S581 and S586, that passed in July, and HR 6218, which is currently

under discussion in the House. Funds are needed for three specific purposes. First, funds are needed for front-end planning. On a national basis, this might amount to \$5-\$10 million for the New England states' planning. Secondly, funds are needed to defray the costs of onshore services consequent upon location of pipelines, tanks, refineries, and petrochemical complexes. And finally, an oil spill fund is necessary to provide some compensation for cleanup costs and damages, should they occur.

Legislation is also needed to get the states involved in the review process on a comprehensive and meaningful basis, without giving them the right of a veto.

Incidentally, I would agree that two aspects of the proposed legislation do not need to go through, and do not provide major benefits for the region. One is changes in the existing bidding procedures, which seem to be working pretty well. The other is the separation of the exploration and development processes, which is the measure the oil companies are fighting the hardest, and which our analysis has shown does not offer significant benefits. Until legislation is passed on some of these issues, it will be difficult for OCS development to occur.

Possible New England Actions

Finally, what should New England do to prepare itself for OCS development and to maximize its net regional benefits? In addition to supporting the two regional aspects of legislation which I have just discussed and which are currently before the House, there are two other needs. First, there is a need to form a regional planning group to take full advantage of Federal funding and to interact with the Federal Government. There are examples of this going on in some of the other regions. FEA and HUD have a joint funding arrangement now where they are part of the OCS planning process in the Mid-Atlantic states and California. More significantly, there is a need for an interdisciplinary team comprised of members of groups represented in this room, to interact with BLM in the preparation of its draft Environmental Impact Statement.

Secondly, there is a need for industry to be more aware of the opportunities that will occur during all parts of the OCS development process. Even though Professor Devanney suggested the bulk of construction activity will go to firms outside the region, New England firms will have significant opportunities to participate in or perhaps to increase the region's 5 percent share of the induced national income associated with OCS development. These opportunities will be accentuated by the fact that concurrent development is forecast by the Federal Government in Alaska, California, the Gulf of Mexico, and the Mid-Atlantic and South Atlantic regions. Offshore development will take place in all of these areas. As a result, importing and exporting of workers will be less likely, so that there will be a chance for onshore employment within the region.

In summary, I agree with Professor Devanney that the opportunity looks bright for OCS development and, if not for all New England industries, at least for New England energy consulting firms.

Discussion

Vince P. Ficcaglia and Michael C. Huston*

We have a number of points in regard to the Devanney paper. In particular we would like to concentrate more on some of the issues that revolve around the economic impacts associated with outer continental shelf (OCS) developments. I think that as far as the topic that Professor Devanney addressed in his paper, the conclusions that he reaches and some of the numbers that he estimates are indeed similar to what we at Arthur D. Little have found. It is true that in any sort of measure of economic impact regarding OCS the most critical input is, of course, just how much oil and perhaps gas would be available off the Georges Bank development. Is there enough in it that we should really be concerned? Or, as the numbers indicate, $3 per head on a regional basis does not seem like an awful lot of money. True, there have been a variety of estimates based upon seismic studies of just how much oil and perhaps gas there is on Georges Bank. Professor Devanney is quite right that, given the nature of the beast, we could go from a very small oil find to quite a substantial amount of oil. This is supported in a number of studies already done in the New England area regarding OCS development commissioned by the Council on Environmental Quality, the New England Regional Commission, even the Massachusetts Port Authority and also the fine study just completed by Professor Gregalunis at the University of Rhode Island. In addition, however, these studies extended the analysis to include the possible implications of more onshore petroleum-related developments in the region. Most of these studies suggest this would create storage problems, onshore creep storage, the problem of gas-processing operations, the likelihood of petroleum-refining operations developing, in some cases petrochemical operations and, of course, construction and capital needs.

Now while Professor Devanney is correct in saying that we cannot credit or, depending upon which side of the fence you are on, blame OCS for the presence, perhaps the likely presence, of petroleum refineries in New England, the potential economic impact to the region of such a development ought to be analyzed. I think it's imperative to be aware of what could indeed occur and how development of such an industry could affect New England. In the past few years a number of proposals have

*Vince P. Ficcaglia is a Senior Economist at Arthur D. Little, Inc. He concentrates in the areas of industrial, regional, public policy, and applied quantitative economics. Mr. Ficcaglia is currently Director of ADL's Economic Analysis and Forecasting Center.

Michael C. Huston is a Senior International Economist and Management Consultant at Arthur D. Little, Inc. He has also directed or participated in a number of studies in the field of energy economics and environmental economic assessment.

been submitted by various industry spokesmen for the likely location of some refinery operations in Maine, New Hampshire, Rhode Island and even in Massachusetts. There's a new book out on the Maine experience by Peter A. Bradford which is quite informative and gives a very good review of the history of this entire issue in Maine. Granted also that it's very likely, given an OCS find in Georges Bank, that the amount of oil we are talking about is not going to answer New England's oil problems. At most, we are probably talking about 250,000 to 275,000 barrels per day, which is less than one-quarter of present New England oil needs. So the issue of OCS oil is not going to solve the problem of oil demand in New England and despite any possible location of refineries in the area, New England is still going to have to import oil into the region.

So should we move toward refinery operations here in New England as a result of the OCS operations? One has to be concerned not with just OCS development but the entire operation of an energy-related industry that could develop and its implications for the six-state area. Professor Devanney has indicated that only a very small number of jobs will be available as a result of OCS operations and that in a region with 600,000 unemployed, 4,000 jobs won't make much impact. However, I think our scale of reference has to be narrowed down a bit, and the jobs and their impacts put in proper perspective, not in terms of the entire region but in terms of the states or the localities that are likely to bear the brunt of most of this impact. Moreover, the total number of jobs we are talking about in the OCS-related operations may indeed be small. If we do include the likely impact that could come about with petroleum-refining operations, some gas-processing operations, onshore creep storage operations, it could increase by a factor of two or so. Still, many of these jobs would be only temporary. The job associated primarily with the rig operations during the exploration phase, and the support of that operation in the exploration phase, lasts at most, I think, about four or five years. The platform-related operations also are of a temporary nature. So that the benefits in terms of jobs or income that could accrue to the state or to the local area have to be weighed in terms of the disruptive effects that the movements in and out of the labor force, in and out of the region, of such numbers of individuals could play on these areas.

In addition, there was little mention in the Devanney paper of some of what I would call the less obvious, maybe in some cases the less glamorous, considerations regarding what could indeed occur under such a development, and certainly could work against some of the benefits that many people like to identify with this sort of development. These concern taxation, more importantly the benefit under present tax laws of having a refinery locate in a particular city or town. The Massachusetts and Rhode Island tax statutes provide very little incentive right now. The question of whether to treat a refinery as real or personal property is now being tried in the courts.

The questions that must be addressed on the environmental side unfortunately were not much alluded to in the paper. These run the gamut of the whole question of impacts upon the real estate market. We have seen some unfortunate results in some places on the Gulf of Mexico, in the Alaska area, and even in areas associated with New York City. These questions include problems of land use, of density, of concentration of activity versus dispersion of activity. All, I feel, must be addressed if one is to get some sense of what indeed we are facing, what is indeed possibly in store for New England and how best we can approach this matter. I think that industry wouldn't mind seeing the states and perhaps the towns start to address some of these issues.

In his paper Professor Devanney applied what he calls the net approach to estimating the economic impacts. Many of the studies that we at ADL and others have done for the Federal Government have adopted what Professor Devanney calls the gross approach to measuring these impacts. In the gross approach what we are identifying is the sum total of the jobs: the income, the earnings, the output and the other variables that would be associated with the development and that would occur in the particular area under study. On the other hand, the net approach tries to estimate the share of total regional effects that represent an increase in national income or national earnings and as a result all payments such as changes in income must be adjusted to reflect the real or opportunity cost of labor that is used in the region. That is, what would the regional resources be earning without the development? I think that is a fair process to go through. However, under conditions of widespread unemployment such as are present in New England most of the increase in income could be credited to the area and to the Nation, and would indeed be close to that estimated by the gross approach.

The final issue that I would like to address briefly is that no matter which measure we talk about, the gross or the net, there is a need to measure these impacts. One approach is to use input-output interindustry techniques. This procedure does allow for a more complete, more comprehensive identification of the possible impacts. The benefits received from this approach far exceed some of the inherent weaknesses.

In summary let me make the following two points. First I think that the studies made over the past four or five years have pretty well identified for the New England region at a macroeconomic level what lies ahead. The amount of oil that could possibly come ashore, the implications for regional income, and the regional number of jobs have been pretty well documented. On the other hand, I think that we have a long way to go in helping out and preparing at the local level for these impacts where most of them are going to be felt. The states and the localities are right now, I think, in a position of great need as investors are scurrying around New England looking for a possible profitable venture. The people of Chatham, of Nantucket and other towns are starting to get up in arms over what they conceive could be some adverse effects to their areas. It is here that we are going to have to direct our focus if we are to realize the benefits and at the same time some of the possible adverse impacts that could result from such a development.

Importance of a New England Energy Policy

Thomas P. Salmon*

The title of my talk is the importance of a New England energy policy. However, we have some fairly disparate views among the New England Governors; these are strong people who occupy the Office of Governor in New England and not all agree on all issues. So I'd rather somewhat obviate the title of my speech today and instead address the parameters of an emerging New England energy policy as they relate to matters we have discussed in Councils of the New England Governors' Conference and the New England Regional Commission, and to some extent to the specific offerings that have been before this Conference this week.

I don't want to repeat the obvious. I think one of the most serious problems we have in this country and in New England is the unwillingness of people to recognize that we have an energy problem. We have a unique situation in this six-state region or rather a unique vulnerability; and I feel that we must reiterate the high points over and over again until we get a broader consensus and understanding of the situation.

When such disparate groups as the National Academy of Science, Mobil Oil Company and the United States Geological Service tell us that domestic petroleum supplies in this country may last no longer than 25 years, I think we ought to pay attention, particularly because New England, as we all know, runs on oil. We run on oil at very great cost — \$1.84 per million Btus of residual fuel to fire the generating plants in this region as opposed to \$0.84 on the national level. To quote the Eisenmenger-Syron report, the cost of energy in manufacturing in this region is \$2.82 as opposed to \$1.22 on the national scene, that is a ratio of 2.3 to 1. The importance of this dependence on oil is shown by the fact that following the embargo in 1973 New England industrial production fell 11.4 percent as opposed to a national decline of 3.8 percent. We are pretty vulnerable.

We have no endogenous resources. Although some would disagree on the exact number, the cost of energy in all forms in New England is about 30 percent higher than in any region in the country, and transportation

*Governor of Vermont and Chairman of the Committee on Natural Resources and Environmental Management for the National Governors' Conference.

costs are also high. As the Eisenmenger-Syron report pointed out so articulately, if we were to do it over again the major industrial center of this country would be on the West Coast. In fact given our relatively poor land with our harsh climate and the high costs of skilled labor, it is remarkable we have done as well as we have.

Obviously we need a strategy. Obviously we need a policy. Obviously we need inputs from the public and private sectors and the world of academia. The strategy or policy will have to be multifaceted. Let us consider some of the elements which should be included. Conservation — really a backburner item on the national scene. My largest single complaint with the emergence of the so-called national energy policy is the notion, implicit in much of what the present FEA administrator and others say, that it is business as usual in this country. There are certain caveats and disclaimers but that is what it comes down to. We are putting all our eggs in one basket on this issue. The basket is the Zarb-Simon syndrome which argues that the price mechanism will solve the energy problem because ultimately the free enterprise system of letting the price of energy rise to the appropriate market level will ration demand. Maybe it will, but it has not thus far. Gasoline in my state is up 20 cents per gallon in the last eight months. There has been no appreciable reduction in consumption. I think we will need a tough conservation policy. The effort must show up in fundamental modifications in the world we live in and in the way we live. To make this work requires tremendous moral leadership from the President of the United States, every governor of this country, every public official in this country and all the groups and associations of people of disparate political and ideological faiths who recognize that the issue is an indispensable component of any national energy policy.

With a major conservation effort, growth in the consumption of electricity is unlikely to reach the 5 1/2 percent suggested earlier, and this should greatly alleviate the financing difficulties of New England's private electric utilities. This in turn will reduce the need for rate increases; and while I am not an expert in this area, I do know that John Q. Public is absolutely bepuzzled by a system that urges significant conservation on the one hand and then penalizes those who conserve with higher electrical costs per kilowatt.

Growth Policy.

We need to consciously define a growth policy in every state of New England. My vote would be to have each state do its own thing. Land-use planning is a concept I very much favor; a national concept of land-use planning which defines fundamental goals and objectives for the states and regions. That's only a piece of it. The role to be played by capital investment in general and the investment of public dollars and capital enterprise in particular should be central to our growth policy. Decisions we make here in New England as to how we spend the $1 billion that is available under EPA grants over the next 18 months for sewerage systems

and clean water can have a profound impact; and I sense we ought to have on line in the six-state region policies that adequately address themselves to this.

Mr. Devanney's paper on OCS was excellent. I for one believe quite strongly that the potentially vast natural resource of the Georges Bank ought to be explored at the earliest possible time with adequate safeguards.

The economic rent issue described in Devanney's paper is very interesting, and the idea of a split between the Federal taxpayer and the investor is particularly beguiling. In Camelot somehow we would find ways and means to tap a major find of oil or more significantly a major find of natural gas on the outer continental shelf for the poor long-suffering consumer of our region who doesn't know anything about the split between taxpayer and investor, but knows a lot about inflation and the price of energy. However, I very much agree with Mr. Devanney's analysis that, with the present national climate the notion of a major find of oil directly and immediately manifesting itself in terms of lower costs for the consumer in this region is unrealistic, unless the combined finds in the whole country are sufficiently significant to dry up our present 38 percent reliance on imported oil.

The debate in Congress today is on the subject of natural gas. In view of this conference, natural gas is not a frontburner item because of the current energy mix here in New England. It is, however, still very important if we consider that natural gas is just about the most perfect fuel: it is clean and cheap; but there is not enough of it, and there will never be enough of it.

As a general proposition, New Englanders would reap significant benefits if the relative costs of imported oil and of natural gas came close together. Consequently, I think a rather strong case can be made here for some form of decontrol. But it is very important to recognize, as pointed out in Devanney's paper, that the effects of decontrol of natural gas should be examined very closely by every region in this country. New England, in particular, should consider what would happen under the hypothesis suggested in the paper — a major find of gas in the Georges Bank.

Refineries.

I for one think we should actively explore the prospect of a refinery in New England, although we must keep in mind that domestic refineries are currently operating below capacity. However, the tendency at the moment appears to be towards expanding existing plants as opposed to building new plants because of environmental considerations and the fastidious nature of people who object actively to the notion of a refinery in regions like New England. Also the OPEC countries may soon be doing more refining and our good neighbor up north, Canada and the Maritime Provinces specifically, already have a capacity to refine product on the terms and conditions that might well be advantageous in the long term to our interest here in the Northeast.

I mentioned Canada. New England Governors have a very interesting dialogue going with the premiers of the five eastern provinces. It is now three years old with the fourth edition to be right here in Cape Cod next June. We are hoping to develop an agreement as to joint ownership of some fairly awesome hydroelectric potential, which if adequately developed would far exceed these provinces' foreseeable needs. Funding does not appear to be a problem but the role of the Canadian Federal government must still be worked out.

Alternate Resources

We have spoken about alternate resources. We in Vermont had a very significant report recently by a Task Force that has examined the potential of wood as a significant energy resource. The conclusion, which appears to be very bullish, says that we have a vast replenishable resource right under our noses, particularly in the three states in Northern New England. If we use it wisely, it can make a significant contribution, perhaps 25 percent, to the electrical energy needs of the people of our state. Instead of letting this report gather dust, as you know most Task Force reports do in the United States, we are doing something. We have just about identified a state institution in Vermont that will convert from oil to wood as a demonstration, and we have hopes for an EPA grant that would permit the Green Mountain Power Company to convert a small plant from oil to wood. I will be supporting legislation this year to create tax incentives encouraging the use of wood and potentially other energy alternatives.

Trade-offs

We spoke during this conference of trade-offs. I see some significant trade-offs. Again, no fantasies here. We are not going to reform the world at this conference because we talked about these things. A choice must be made between a significant contribution from coal and clean air — at least until we have developed economical synthetic approaches such as gasification — and I am inclined to think that if the American people were consciously and intelligently given the choice, they would come down on the side of clean air. I have skipped the nuclear power issue for I did not see a position paper on nuclear power. However, I understand it has been discussed at the conference. This is a very tender issue in the country, perhaps more tender in some respects here in New England than anywhere else. I see essentially three options on the issue of nuclear power. One, we could have an outright moratorium. The cost of conversion to fossil fuel would be extraordinarily high. That option is unlikely. Option two, as I see it, is full speed ahead on development of the fast breeder reactor. I sense for a variety of reasons that that option today

is somewhat unlikely, based on our current climate, and available technology on the subject. The third option is to continue developing the present reactor but to stop short of going full speed on the fast breeder and to hold off the recycling of highly processed petroleum until the future process is safely in place. Very sensitive, very difficult issue, and I didn't come down to Martha's Vineyard today to provide an answer.

Finally, I sense that for all of us, whether Governors, Members of Congress, members of the business and academic communities, and the adversary groups from all the states, the politics of truth is suddenly coming of age in this country and this region. We must come together and address these problems and make tough decisions that will be significant not only to our major allies but to the quality of life that our children and the kids after that will enjoy.

CONFERENCE PARTICIPANTS

M. A. ADELMAN, *Professor of Economics, Massachusetts Institute of Technology*
FREDERICK W. ALLEN, *Executive Assistant to the Director, The Office of Inter-Governmental Regional and Special Programs*
JOHN J. BACON, *Senior Vice President, Boston Gas*
RAYMOND BEAUREGARD, *Economist, Northeast Utilities*
PETER BRADFORD, *Chairman, Maine Public Utilities Commission*
ANDREW F. BRIMMER, *Professor, Harvard Business School*
LYNN E. BROWNE, *Economist, Federal Reserve Bank of Boston*
LOUIS W. CABOT, *Chairman of the Board, Cabot Corporation*
EDWIN L. CALDWELL, *Vice President and Economist, The Connecticut Bank and Trust Company*
R. MURRAY CAMPBELL, *Engineer and Project Manager, Stone & Webster Engineering Corporation*
LANCE CARDEN, *Assistant to the Editor, Christian Science Monitor*
PETER B. CLARK, *Executive Director, New England Energy Policy Council*
GEORGE H. CLAY, *President, Federal Reserve Bank of Kansas City*
BRUCE DAVIDSON, *Editorial Writer, Boston Globe*
JOHN DEVANNEY, *Associate Professor, Massachusetts Institute of Technology*
ROBERT W. EISENMENGER, *Senior Vice President and Director of Research, Federal Reserve Bank of Boston*
VINCE FICCAGLIA, *Manager of Economic Forecasting and Analysis, Arthur D. Little, Inc.*
NORMAN S. FIELEKE, *Vice President and Economist, Federal Reserve Bank of Boston*
THOMAS FITZPATRICK, *Research Director, New England Regional Commission*
HEYWOOD W. FLEISIG, *Economist, Board of Governors of the Federal Reserve System*
LILLIAN F. FOSTER, *Managing Editor, The New Englander*
PETER FOUSEK, *Economic Adviser, Federal Reserve Bank of New York*
THOMAS J. GALLIGAN, *President, Boston Edison*
DANIEL GANS, *Consulting Engineer, Stone & Webster Engineering Corporation*
FRANCIS B. GUMMERE, *Vice President, William Filene's Sons Company*
KENNETH I. GUSCOTT, *President, Ken Guscott Associates*
WILLIAM HARSCH, *Chairman, Rhode Island Department of Business Regulation*
ROBERT C. HOLLAND, *Member, Board of Governors of the Federal Reserve System*
WILLIAM M. HONEY, *President, Martha's Vineyard National Bank*
JAMES M. HOWELL, *Senior Vice President and Chief Economist, First National Bank of Boston*
WILLIAM R. HUGHES, *Vice President, Charles River Associates*
ROBERT A. JOHNSTON, *Assistant Vice President and Economist, Federal Reserve Bank of San Francisco*
PETER JUDD, *Consultant, Northeast Utilities Service Company*
ALAN KAUFMAN, *Director and Counsel, Land Use and Coastal Zone Project, Conservation Law Foundation*
JOHN P. KENNEY, *Coordinator, Federal Reserve Bank of Boston*
HENRY LEE, *Director, The Commonwealth of Massachusetts Energy Policy Office*
PAUL A. LONDON, *Director, New England Economic Research Office*
ANTHONY T. LUONGO, *Protection Department, Federal Reserve Bank of Boston*
JAMES J. MacKENZIE, *Joint Scientific Staff, Massachusetts Audubon Society*
RICHARD B. MAFFEI, *Dean of Business School, Boston College*
JOHN J. MARINO, *Commissioner, Massachusetts Department of Commerce and Development*
NELSON J. McDERMOTT, *JR., President, Hitchiner Manufacturing Company, Inc.*
JOHN A. S. McGLENNON, *Regional Director, U.S. Environmental Protection Agency*
JAMES A. McINTOSH, *First Vice President, Federal Reserve Bank of Boston*
PETER J. McTAGUE, *President, Green Mountain Power Company*
RUSSELL F. MERRIMAN, *Cochairman, New England Regional Commission*
ROBERT W. MITCHELL, *Regional Administrator, Federal Energy Administration*
FRANK E. MORRIS, *President, Federal Reserve Bank of Boston*
GUY W. NICHOLS, *President and Chief Executive, New England Electric System*
P. ANDREWS NIXON, *President, Dead River Company*
MARSOM B. PRATT, *Senior Vice President, Adams, Harkness and Hill, Inc.*
WILLIAM REINFELD, *Arthur D. Little, Inc.*
JOCH D. RITCHIE, *President, Asiatic Petroleum Company*
THOMAS P. SALMON, *Governor, State of Vermont*
THOMAS SCOTT, *President, New England Energy Policy Council*
WERNER E. SIEVERS, *Associate Technical Director, Mitre Corporation*
ROBERT P. SMITH, *Vice President, United Engineers and Contractors Inc.-Philadelphia*
WILSON S. SNOW, *Audio Visual Technician, Federal Reserve Bank of Boston*
ROBERT M. SOLOW, *Institute Professor of Economics, Massachusetts Institute of Technology*
ALEX M. STEINBERGH, *Principal and Senior Economist, Resource Planning Associates, Inc.*
CHAPMAN STOCKFORD, *Executive Director, New England Governors Conference*
ANNE STRAUS, *Assistant to Senator Edward M. Kennedy*
RICHARD F. SYRON, *Assistant Vice President and Economist, Federal Reserve Bank of Boston*
JOSEPH VITKA, *Executive Director, New England Governors' Conference*
STANLEY WALLERSTEIN, *Aide to Congressman Michael Harrington*
HENRY C. WALLICH, *Member, Board of Governors of the Federal Reserve System*
HERBERT F. WASS, *Assistant Vice President and Secretary, Federal Reserve Bank of Boston*
JOHN W. WEBER, *Senior Consultant, Temple, Barker and Sloane, Inc.*
HELMUT F. WENDEL, *Assistant Adviser, Board of Governors of the Federal Reserve System*
KENNETH A. WOOD, *JR., Acting Deputy Commissioner, Department of Planning and Energy Policy*
MARTIN B. ZIMMERMAN, *Research Associate, Massachusetts Institute of Technology*

Copies of this Publication
are available, upon request, from the
PUBLIC INFORMATION CENTER
FEDERAL RESERVE BANK OF BOSTON
BOSTON, MASSACHUSETTS 02106