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COMMONWEALTH OF MASSACHUSETTS

MASSACHUSETTS REFUSETECH INC.
CONTRACTUAL REQUEST FOR
ADJUSTMENT TO SERVICE FEE

DIRECT TESTIMONY OF

PAUL CHERNICK
Resource Insight, Inc.

ON BEHALF OF

MASSACHUSETTS REFUSETECH INC.

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1. INTRODUCTION AND QUALIFICATIONS

1.1 Qualifications

My name is Paul L. Chernick. I am President of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts.

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

I was a Utility Analyst for the Massachusetts Attorney General for over three years, from late 1977 until May of 1981. In that capacity, I was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options.

As a Research Associate at Analysis and Inference, from 1981 to 1986, and in my current position, I have advised a variety of clients on utility matters. My work has considered, among other things, the need for, cost of, and cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is attached to this testimony as Attachment MRI-PLC-1.

I have testified approximately seventy times on utility issues before various regulatory, legislative, and judicial bodies, including the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Maine Public Utilities Commission, the Vermont Public Service Board, the Texas Public Utilities Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Illinois Commerce Commission, the Minnesota Public Utilities Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume. Subjects I have testified on include nuclear power plant construction costs and schedules, nuclear power plant operating costs, power plant phase-in procedures, the funding of nuclear decommissioning, cost allocation, rate design, long range energy and demand forecasts, utility supply planning decisions, conservation costs and potential effectiveness, generation system reliability, fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

I have written a number of publications on utility planning and ratemaking issues, including rate design, cost allocations, power plant cost recovery, conservation program design and cost-benefit analysis, and other ratemaking issues. These publications are listed in my resume.

1.2 Introduction

This testimony examines the reasons and causes for the reduction in the unit price paid by the New England Power Company (NEPCo) to Massachusetts Refusetech Inc. (MRI) for power produced by the NESWC resource recovery facility in North Andover, Massachusetts. It addresses the issue of whether the low level of energy rates paid by NEPCo to date, and those which are likely to be paid in the future, were foreseen when the Service Agreements between MRI and NESWC were executed in April 1981. To be as comprehensive as possible, I have included projections published within about two years of April 1981, in either direction.

This testimony is organized in the following manner:

- In Section 2, I describe the relationship between MRI and NEPCo, the manner in which the rates NEPCo pays MRI is computed, and the major factors affecting those rates.

- In Section 3, I discuss the expectations for utility fuel prices and purchased power rates which were current in the late 1970s and early 1980s, among Massachusetts utilities, regulators, and public-interest advocates.
- Section 4 presents my conclusions.

1.3 Summary of Conclusions

The difference between the projected and actual electricity purchase rates occurs primarily because of the precipitous decline in oil prices, the significant decline in coal prices and the dramatic reduction in the expectation for future fuel prices between the early 1980s and the present day. This decline was not foreseen or expected by the participants in the electric utility planning and regulatory process, nationally, regionally, or in New England.

In the late 1970s and early 1980s, oil prices were generally expected to rise over time. This view, held by national forecasting firms, utility regulatory commissions, electric utilities, and consumer advocates, was rarely questioned. At that time, I was a utility analyst with the Massachusetts Attorney General's office and was active in a wide range of utility planning cases involving load forecasts and the need for additional nuclear power plants. While the Attorney General and other consumer interests tended to disagree with utilities on many issues, we agreed that continuing increases in oil prices were inevitable, or at least overwhelmingly likely.

Although fuel prices were expected to rise dramatically during the 1980s, they have actually fallen. The price of the oil used by NEPCo in its power plants fell approximately 50% from 1981 to 1986. The price of coal burned by NEPCo fell about 25% in the same period.

Had fossil fuel prices reached the levels in the late 1980s which were expected in the early 1980s, NEPCo's purchased power rates would have been similar to those projected by MRI, NESWC, and other parties in the early 1980s. In particular, the projections of purchased power rates in the Weston Feasibility Report, quoted in the MRI Contractual Request for Adjustment to Service Fee, reflect the levels of purchased power costs that reasonably would have been foreseen in the early 1980s and would have been realized, but for the reduction in fuel prices.

2. NEPCO RATES FOR POWER PURCHASES FROM THE NESWC PLANT

2.1 The Energy-related Relationships between MRI, NESWC and NEPCo

2.1.1 Contractual relationships

MRI operates the NESWC facility under a Service Agreement with, and receives payments from, the NESWC communities. MRI sells electrical energy to NEPCo under a 20-year contract that specifies the costing methodology, but not prices, to be used in determining the payments. Of the electricity revenues, MRI retains 10.5% as part of its compensation, while the remaining 89.5% is credited to the NESWC communities. Over a certain threshhold, MRI gets 50% of the electricity revenues.

2.1.2 NEPCo and its affiliates

Several affiliates of the New England Power Company (NEPCo) may be mentioned in this testimony or elsewhere in the arbitration. NEPCo is a subsidiary of the utility holding company, New England Electric System (NEES). NEPCo owns and/or operates the majority of the generation and transmission facilities owned by the NEES companies.[1]

1/ Narragansett Electric Company, the NEES retail subsidiary serving most of Rhode Island, owns some generation (which it owned prior to the formation of NEES), all of which is under contract to NEPCo. The various retail companies own small amounts of transmission, also for historical reasons.

Another NEES subsidiary, the Massachusetts Electric Company (MECo), provides retail electric service in about half of Massachusetts.[2] MECo purchases virtually all its power (including transmission services) at wholesale from NEPCo.[3]

NEES also has a subsidiary, New England Energy, Inc. (NEEI), which obtains fuel for NEPCo power plants. In the early 1980s, NEEI engaged in oil exploration activities that now produce crude oil and gas that NEEI trades for oil products to be delivered to its power plants. NEEI is also responsible for the fuel price forecasts used by NEPCo and other NEES subsidiaries.

2.1.3 Regulation of NEES operations in Massachusetts

The various NEES operations in Massachusetts are regulated by the Massachusetts Department of Public Utilities (DPU) and the Federal Energy Regulatory Commission (FERC). The DPU regulates retail power transactions and rates, and hence most MECo activities. The DPU also has some limited regulatory authority over NEPCo; for example, NEPCo's long-term financings must be

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2/ Similarly, Narragansett Electric Company provides service in most of Rhode Island, and Granite State Electric Company provides service in small parts of New Hampshire.

3/ A small amount of MECo power is purchased directly from non-utility generators located in its service territory. Most non-utility generators located in MECo's service territory, including NESWC, sell their power to NEPCo, which then averages that power in with its other sources and resells it to both affiliated and smaller non-affiliated customers.

approved by the DPU. NEPCo's rates for its sale of power to MECo, its other retail affiliates in other states, and unaffiliated utilities are wholesale transactions, which are regulated by the FERC.

In 1978, Congress passed the Public Utilities Regulatory Policy Act (PURPA), Section 210 of which required that utilities purchase power from certain "qualifying facilities" (QFs) at the utility's avoided costs. Those avoided costs were defined in PURPA and in the implementing FERC regulations (issued in 1980) to be the costs the utility avoids by purchasing the power. The qualifying facilities included cogenerators, which simultaneously and efficiently produce both electricity and useful heat, and "small power producers," power plants under certain size limits and powered by renewable energy or waste materials. Waste-to-energy plants, including the MRI facility, are small power producers, and hence QFs.

Under PURPA, rates for power purchased from QFs by each utility were to be set by the authority which regulated that utility's rates. While FERC has certain responsibilities for issuing general regulations, certifying QFs, and resolving some disputes, most of the detail of setting utility avoided-cost rates fell to the state regulatory commissions, such as the DPU. The DPU did not issue regulations implementing PURPA until 1981, in Docket 535. Those regulations described the manner in which energy and (in some cases) capacity charges were to be computed, but did not require (or even encourage) the utilities to offer long-term fixed-price contracts to QFs. The regulations envisioned the purchase of power in each year at avoided energy costs that would be recalculated each year, even for contracts signed many years previously. Long-term contracts with any assurance of future prices were not required until the issuance of the order in DPU 84-276 in August 1986. DPU 84-276 also instituted bidding by QFs to supply power to utilities, although MECo was allowed to pursue a negotiated approach.

The DPU has asserted jurisdiction over NEPCo purchases from QFs under PURPA. NEPCo has not accepted that authority and has filed contracts with the DPU for information purposes only. The DPU has never rejected a NEPCo QF contract, so the jurisdictional question remains unresolved. Since 1986, NEES acquisitions of QF power in Massachusetts have been primarily through MECo; prior to that time, most power was purchased through NEPCo, as in the case of the MRI facility. NEPCo started contracting for significant amounts of QF power in 1981, prior to significant activity in this field by most other Massachusetts and New England utilities. Most Massachusetts utilities contracted for very little QF power prior to the 1986 order in DPU 84-276.

Thus, the form of the power sales agreement MRI signed with NEPCo was the only option typically available in 1981, and indeed until 1986. Similarly, NEPCo was the only feasible purchaser of NESWC power at that time.

2.2 Computation of NEPCo Purchased-Power Rates

I have previously defined "avoided costs" as the costs avoided by a utility through a purchase of power from a QF. Two similar concepts used in various utility applications are "marginal costs" and "incremental costs." Marginal costs are the costs at the margin; that is, the cost of producing one more (or the savings from producing one less) unit of power. Incremental costs are the costs of an increment of load; that is, the increased cost of serving a specified increase in load.[4] The incremental costs are usually stated as unit costs; if serving an increment of 100 million kilowatt-hours in a year would cost $5 million, the incremental cost would be stated as 5 cents/kWh. Studies of marginal costs and/or incremental costs are often used in determining avoided costs.

None of the cost concepts discussed in the preceding paragraph -- avoided, marginal, or incremental -- has any close connection to average costs, the ratio of total cost to total power output or sales, for several reasons. First, entire categories of costs are reflected in the average, but not the

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4/ "Incremental costs" also often include "decremental costs," the savings from not serving a decrease in load.

avoided, cost. Such categories include the costs of transmitting and distributing QF energy to end users, billing and metering, and corporate overheads. Generally, only the costs of building and operating power plants are considered in setting avoided costs. Second, even in its power plants, the utility may have either high or low costs that affect the average, but will not be duplicated in the future and will not affect avoided costs. Third, various types of existing plants are not all equally used by utilities, so the avoided variable costs due to a QF usually will not be the same as the average variable costs for that year.

At this point, it may be useful to discuss the terms in which power purchased from QFs is measured. An electric utility must provide two types of power generation services. First, it must provide enough capacity to meet the maximum load on the system, even when some generating units are out of operation. Capacity is measured in kilowatts (kW) and in megawatts (MW), which are 1000 kW. Second, it must provide the energy desired by customers throughout the year. Energy is measured in kilowatt-hours (kWh), the units used in retail rates, as well as megawatt-hours (MWH), which are equal to 1000 kWh. Levels of electric demand vary over the year, generally being higher during the day and lower at night, higher on hot summer days and cold winter evenings, lower in mild weather.[5]

To meet this range of power requirements, utilities usually have a range of power plants. Some power plants, such as hydroelectric and nuclear plants, are very expensive to build, but inexpensive to run, and are used heavily to generate as large amounts of electricity as possible. Others, such as oil-fired combustion turbines, are inexpensive to build and expensive to run, and are therefore built primarily to meet rare high loads and to provide backup when other units break down. They are operated for very few hours per year.

To minimize costs, utilities attempt to minimize the operation of their generating units with the highest operating costs. With a few minor exceptions, utilities run their least expensive energy sources, such as hydroelectric and nuclear plants, whenever they are available.[6] When load is higher than the available capacity of these units,[7] the utility operates more expensive plants, such as coal plants. Once the coal plants are

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5/ Because of the large changes over the course of a day, demand levels are usually reported on an hourly basis. The level of demand at any hour is referred to as the "load." Since there are 8760 hours in a non-leap year (365 days * 24 hours/day), utilities plan for an annual demand pattern composed of 8760 hours.

6/ Recall that only variable operating costs are relevant in deciding which units to run.

7/ This is essentially always the case in New England.

all operating, the utility turns on its lowest-cost oil plants, then progressively more expensive oil plants until load is satisfied. This approach of using the lowest-cost plants first, is known as "economy dispatch."

In the simplest situations, economic dispatch operates on an hourly basis, with the utility operating in each hour the least expensive available plants, up to the amount of required load. For various technical reasons, actual economic dispatch is somewhat more complicated.

The operating cost of a fossil-fueled unit, such as an oil or coal plant, consists of two portions. First, there is a relatively small variable operating and maintenance (O&M) cost, covering such cost as wear and tear, disposal of ash, and charges for water consumptions. Second, there is a much larger fuel cost.

The fuel cost for any particular generating unit is determined by the unit's fuel prices and its efficiency. Fuel prices are reported in many ways, but one common approach states fuel prices per MMBTU (million British thermal units). Power plant efficiencies are usually reported as "heat rates," the number of BTUs necessary to generate one kWh. The heat rates of NEPCo's large oil-fired and coal-fired power plants, and most similar units, fall in the range of 9,000 to 11,000 BTU/kWh. The cost of fuel in $/kWh is thus the fuel price (in $/MMBTU) times the heat rate (in BTU/kWh), divided by one million.

The contract between NEPCo and MRI provides for payments for energy delivered by MRI to NEPCo, but does not provide for capacity payments. Thus, the energy revenues received by MRI and NESWC are dependent on the number of kWh delivered to NEPCo. NEPCo pays different rates for power delivered in the high-load on-peak period (defined as 7 a.m. to 11 p.m. on weekdays, or about 4,000 hours/year) and power delivered in the off-peak period (all other hours).

NEPCo computes the rates (cents/kWh) it will pay MRI on a monthly basis. The on-peak rate is computed by multiplying NEPCo's monthly fuel adjustment clause (FAC) rate by an "on-peak factor;" similarly, the off-peak is computed by multiplying NEPCo's monthly FAC rate by an "off-peak factor."

The two factors are computed late in each calendar year, for the next year, by estimating the incremental cost on-peak and off-peak for the next year, and the FAC. The projected on-peak incremental cost per kWh is divided by the projected FAC rate to determine the on-peak factor. The off-peak incremental cost per kWh is divided by the projected FAC rate to determine the off-peak factor. The FAC is charged to all NEPCo firm requirements sales and recovers all fuel costs. It therefore is essentially the average cost of fuel.

NEPCo performs an avoided-cost estimation only once per year. From that estimation process, NEPCo estimates the ratios of the on-peak incremental cost and the off-peak incremental cost to the average cost of fuel as estimated for the FAC. The ratio of the on-peak incremental cost to the FAC is the "on-peak factor", while the ratio of the off-peak incremental cost to the FAC is the "off-peak factor." For each of the following 12 months, NEPCo multiplies the actual FAC by the two factors to derive the short-term incremental costs to be paid to the facilities which sell to NEPCo under those rates. Thus, during a year, the "incremental costs" vary only to the extent the FAC varies.

The existence of NEPOOL has complex effects on NEPCo's actual avoided costs. However, since the purchased power rates are determined essentially as if NEPOOL did not exist, the overall effect on the rates is small. One area in which there may be some effect concerns the difference between NEPCo and NEPOOL fuel mixes. NEPCo uses considerably less oil than does NEPOOL as a whole, primarily because of NEPCo's significant coal capacity. Coal may therefore be the marginal fuel for NEPCo in some hours. However, if coal were the marginal fuel for NEPCo for a large portion of the year, significant amounts of NEPCo coal capacity would not be used in its own-load dispatch, and would therefore be available to other NEPOOL utilities for little benefit to NEPCo. In this situation, it would be to NEPCo's advantage to sell off some of its under-utilized coal capacity to more oil-dependent utilities. As long as NEPOOL is predominantly oil-fired at the margin, coal is unlikely to be the dominant fuel on NEPCo's own-load dispatch, since any significant excess of coal will be sold to more oil-dependent utilities. This is especially true when oil prices are much higher than coal prices.

Under the contract with NEPCo, MRI receives 90% of the incremental energy cost. While a facility signing a similar contract today would expect to receive essentially 100% of the incremental energy cost, and probably some avoided capacity costs as well, utilities were in a very good bargaining position with QFs in the early 1980s, prior to the DPU decisions in DPU 535 and DPU 84-276, and could extract considerable concessions from QFs.

2.3 The Major Factors Affecting NEPCo Purchased Power Rates.

The primary incremental or marginal fuel in New England is oil. This has been true since at least 1970. It certainly has been true since I became involved in New England electric utility regulation in 1977. Furthermore, virtually all observers have expected oil to remain the dominant incremental fuel for New England utilities throughout the foreseeable future, which generally has been 10-20 years.

Utilities burn several types of oil in a few types of plants. Most of the oil burned by New England electric utilities is "heavy" fuel oil, also called "residual" oil, "#6" oil, or "Bunker C" fuel oil. Residual oil is quite literally the residue left in the refinery after the lighter constituents of the oil (e.g., gasoline) are refined off. It is viscous and difficult to handle -- in New England winter weather, #6 oil must be heated to flow -- and is used only by utilities and other large users (e.g., heavy industry, very large buildings, and some large ships). At times, #6 oil is less expensive than crude oil. Within the category of residual oil, the major distinction between grades is the sulfur content. High-sulfur oil is less expensive, in part because it cannot be used in many places (e.g., California, New York City) due to air quality concerns. Sulfur content of residual oil burned in New England varies from 0.5% to 2.2%; each plant typically burns oil close to the maximum allowed under its air quality permits. NEPCo's major oil-fired power plants, at Brayton Point and Salem, usually burn 2.2% sulfur oil. Smaller units located in Providence burn 1% sulfur oil.

Peaking units in New England (and in most of the country) burn distillate oil, the lighter fractions of the oil, distilled off at the refinery. Most of the distillate oil burned by New England utilities is #2 or diesel oil, which is essentially the same as home heating oil.[8] Distillate oil is considerably more expensive than residual or crude oil. The price varies only slightly with sulfur content, which is quite low (0.3% in Massachusetts).

Oil is burned in four kinds of power plants. The major type of oil-burning plant in New England is the steam-electric power plant, in which residual oil is burned in a boiler to produce steam, which is then used to turn a turbine and generate electricity. These plants are "external combustion" units, because the combustion occurs outside the (steam/water) system that actually generates electricity. The major NEPCo oil plants at Brayton Point and Salem are steam-electric units,[9] as are the units in Providence. NEPCo also owns peaking oil-fired plants of two types, gas turbines (also called "combustion turbines" or "jets") and diesels. Gas turbines use the hot combustion gases to turn a turbine (and hence look much like a jet aircraft engine, which works in a similar manner). In diesels, combustion gases move pistons which move a generator. Both gas turbines and diesels are "internal combustion" engines, since the combustion gases are actually responsible for moving the generator. Both gas turbines and diesels in New England burn distillate. The

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8/ A few units use #1 oil, which is similar to jet fuel and kerosene.

9/ The coal plants are similar in design, and have also burned oil for part of their lives.

fourth type of oil-fired power plant combines gas turbines with a waste-heat boiler that generates steam for a steam turbine, and is hence called a "combined-cycle" plant. NEPCo currently owns no combined-cycle capacity except for a small entitlement in the Ocean States plant, which came on line at the end of 1990.[10]

NEPCo's incremental rates are determined primarily by the price of oil. I have determined this from regression analyses on MECo estimates of avoided costs for a range of oil prices. Attachment MRI-PLC-2 contains data from a 1987 study MECo performed for the DPU. MECo avoided-cost projections are very sensitive to oil prices, varying by 0.895 cents for every $/MMBTU change in oil prices.[11] This is equivalent to a plant with a heat rate of 8,950 BTU/kWh. The sensitivity to coal prices is much lower, 0.2776¢ for every $/MMBTU change in oil prices. This is equivalent to a plant with a heat rate of 2,776 BTU/kWh. The marginal mix of avoided energy costs is thus equivalent to an average heat rate of 11,726 BTU/kWh, with oil marginal 76.3% of the time, and coal marginal the other 23.7% of the time.

Oil has been a significant portion of NEPCo's total energy mix throughout the last decade. Figure 2.3.1 shows the overall

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10/ Some New England municipal utilities and non-utility generators own combined cycle plants, and others are planned or under construction. NEES is converting the oil-fired South Street plant in Providence to natural-gas-fired combined cycle operation.

11/ I used prices for 2.2% sulfur #6 oil to represent all oil.

NEES fuel mix for 1981-90. A few years are missing because the actual mix was not reported in any NEES annual report.

2.4 The History of NEPCo Purchased Power Rates

2.4.1 Comparing costs over time

Prices and costs in different years can be compared over time in two ways. First, the costs for each year can be stated in that year's dollars without any adjustment for inflation. These "nominal" or "current" dollar values are the amounts that would appear on invoices and accounting statements in each year. In nominal terms, gasoline cost 37 cents/gallon in 1970, $1.43/gallon in 1980, and 94 cents/gallon in 1987. Of course, a dollar was worth more in 1970 than in 1980: what $1 would buy in 1970 would cost $2.04 in 1980 and $2.80 in 1987.[12]

Second, the costs can be adjusted for inflation so that the dollars used are more comparable. These "inflation-adjusted," "real," or "constant" dollars are used in many economic analyses but rarely appear in normal commercial applications. In constant

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12/ The rate of inflation varies with the type of cost being measured. Usually, constant-dollar costs are computed with an inflation index (or deflator), which averages the cost increases in a broad market basket of goods and services. The Consumer Price Index (CPI) uses a mix of goods and services purchased by households; the Gross National Product (GNP) deflator uses the national mix of goods and services. These computations are based on the GNP deflator.

1970 dollars,[13] gasoline cost 37 cents/gallon in 1970,[14] 70 cents/gallon in 1980, and 34 cents/gallon in 1987.

2.4.2 NEPCo incremental energy rates, 1980-90

Table 2.4.1 displays NEPCo fuel adjustment charges and incremental energy rates, as computed for the MRI/NESWC contract, for the period 1977-1990. The incremental energy rate rose rapidly in the period 1979-81, fell back slightly in 1982, continued to sag gradually in 1983 and 1984, collapsed in 1985 and 1986, and has stayed at roughly the same level since. Between 1981 and 1989, the incremental energy rate fell 50%, from 6.0¢ to 3.0¢/kWh.

Table 2.4.2 displays NEPCo, New England, and national oil costs in the period 1977-1990. This Table shows that oil prices have fallen in much the same way as NEPCo's incremental energy rate. Between 1981 and 1989, for example, the cost of oil burned by New England utilities fell 49%.

Table 2.4.2 also shows the relationship between the costs of various types of oil. Residual oil prices generally follow the prices of crude oil, but is somewhat less expensive. NEPCo residual oil is usually close to the average national price of

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13/ The phrase "1970 dollars" is abbreviated "1970$."

14/ This value is the same as in the previous paragraph, since that cost was already stated in 1970$.

residual oil, but is always lower than the average price of oil burned in New England (which includes higher-grade oils).

Table 2.4.3 displays similar data for coal prices, which have also declined, although not as much as have oil prices. Coal costs have fallen only about 13-38% since their peak in 1982. The decline can be seen in minemouth prices, national average delivered prices, and New England utility costs. NEPCo coal costs were rather volatile in the early 1980s; the 1989 price was 15% lower than 1980, and 9% higher than 1981.

3. EXPECTATIONS IN THE LATE 1970s AND EARLY 1980s

3.1 Introduction: Expectations and Reality

The realities of the late 1980s discussed in the previous section differed substantially from the expectations of the early 1980s. In the early 1980s, oil prices were expected to rise substantially in real terms, coal prices were expected to rise at least modestly in real terms, and general inflation rates were expected to be high. Thus, nominal fuel prices were expected to rise rapidly. As a result, the incremental energy rates (or other measures of avoided costs) were also expected to rise rapidly.

The decline in actual and expected fuel prices had two components. First, general inflation has been much lower than generally expected in the early 1980s, when projections of 8-10% general inflation were common and projections below 7% rare. Table 3.1.1 lists some the general inflation projections I have located from this period. Actual inflation from 1981-1990 was only 3.8%.[15] Hence, prices of most commodities tended to rise more slowly than was expected in the early 1980s. If the real prices of fuels were the same as they are today, but inflation had been 9% rather than 3.8% from 1981-1990, nominal fuel prices,

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15/ This inflation rate is for the GNP deflator, from the 2/91 Economic Report of the President. I discuss the meaning of deflators in Section 2.4.

and hence the purchased power rate, would be about 55% higher than actual 1990 levels.

Second, fuel prices have failed to rise faster than inflation, as was generally expected in the early 1980s. Expected real escalation rates in the 1980s varied widely, depending on the time of the forecast and the optimism or pessimism of the forecasters, but most forecasters in this period expected oil prices to rise faster than inflation. At one extreme, the American Gas Association (AGA) 1982 and 1983 projections assumed real increases of less than 0.1% annually; at the other, the DOE 1981 projections were for 6% real escalation. If the real escalation in oil prices had been 3% from 1981 to 1990, oil prices would have been close to $10/MMBTU by 1990, even with the low actual general escalation rates.[16]

Third, fuel costs have fallen in real terms. The price of the oil used by NEPCo in its power plants fell approximately 50% from 1981 to 1986. The price of coal burned by NEPCo fell about 25% in the same period. Fuel prices have been essentially stable since 1986, with the exception of short-term swings (notably in late 1990). If fuel prices had simply stayed constant in real

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16/ Here and in the following summaries, I report fuel prices in $/MMBTU. At typical steam-plant heat rates of 10,000 BTU/kWH, each $1/MMBTU produces a fuel cost of 1¢/kWh. Thus, $10/MMBTU is roughly equivalent to 10¢/kWh. Recall that recent NEPCo incremental energy rates have been under 3¢/kWh.

terms, oil would have cost over $7/MMBTU and coal about $3.5/MMBTU by 1990.

Overall, oil prices in 1990 wound up 50-75% lower than projected in the early 1980s. Coal prices were 20-50% lower than projected.

3.2 Fuel Price Projections

Between December 1977 and May 1981, I was a utility analyst for the Massachusetts Attorney General. In that regard, I was active in a number of proceedings before the DPU and the Energy Facilities Siting Council (EFSC) on electric utility load forecasts, rate design, and supply planning, especially with regard to utility proposals to build nuclear power plants (i.e., Pilgrim 2 in Massachusetts and Seabrook in New Hampshire). The Attorney General (and other public-interest intervenors) tended to disagree with a wide range of utility assumptions, including the attractiveness of electricity to customers, future efficiency levels, rates of economic growth, the relationships between economic growth and electricity usage, the sensitivity of electricity usage to price, the cost of new power plants (especially nuclear), and the operational characteristics of those plants. Oil price forecasting was one of the few areas in which we tended to agree with the utilities. Almost without exception, the participants in Massachusetts electric utility regulation accepted (with little real question) the view that oil prices were bound to continue rising, in both nominal and real terms.[17]

3.2.1 National forecasts

Tables 3.2.1 - 3.2.15, and Figures 3.2.1 - 3.2.10 display the fuel price projections of several national forecasters for the period 1979-83. The most relevant data are those from 1980 and 1981, which represent expectations at the time of the signing of the Service Agreements. The sources include the commercial forecasting services of Data Resources Inc. (DRI) and Wharton Econometric Forecasting Associates (WEFA); the US Department of Energy (DOE) and its Energy Information Administration (EIA); the American Gas Association (AGA); and some miscellaneous sources. I emphasize the projections that are available in nominal terms. I recollect that DRI, WEFA, and DOE sources were frequently cited by Massachusetts electric utilities. DRI is currently the dominant source of fuel price projections for Massachusetts electric utilities, and has been for most of the 1980s.

The data in Tables 3.2.1 - 3.2.15 support my recollections of the common wisdom of the early 1980s. I present the price

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17/ Short-term fluctuations were expected, including the possibility of periods of price decline or stagnation. The overall long-term trend was expected to be strongly upward.

forecasts in $/MMBTU, which is roughly equivalent to the fuel cost of electricity in ¢/kWh.

The DRI projections are summarized in Tables 3.2.1 - 3.2.3 and Figures 3.2.1 - 3.2.2. Projections are provided for crude oil prices in Table 3.2.1, residual oil in Table 3.2.2 and Figure 3.2.1, and coal (for national average delivered prices) in Table 3.2.3 and Figure 3.2.2. Recall that DRI forecasts were and are widely used by New England utilities, and have been accepted by regulators.

The 1980/81 Winter DRI forecast, which was current at the time the Service Agreements were signed, projected $15.2/MMBTU for residual oil in 1989. Coal would have been more than $4/MMBTU as a national average, with New England coal prices somewhat higher.

Later DRI forecasts, which were not available at the time of the Agreements, were considerably lower, especially for oil. By the winter of 1982/83, DRI's projection of oil prices in 1989 had fallen to about $8.2/MMBTU. This was still about 3.5 times the actual cost of residual oil in 1989 ($2.33/MMBTU).

The WEFA projections are summarized in Tables 3.2.4 - 3.2.5 and Figures 3.2.3 - 3.2.4. WEFA's 1981 expectations for crude oil prices were about 30% lower than those of DRI, but were still far above actual results. The coal price WEFA forecast in 1981 for 1989 was about twice the actual price.

The DOE/EIA projections are summarized in Tables 3.2.6 -3.2.11 and Figures 3.2.5 - 3.2.10. The 1981 base forecast for crude oil estimated about $14/MMBTU in 1989, while the "low" forecast projected over $10/MMBTU. These are respectively about 5 times and 3.5 times the actual price. Even as late as 1983, the DOE low forecast was for $5.81/MMBTU, almost exactly twice the actual price.

The other projections available in nominal terms are summarized in Tables 3.2.12 - 3.2.13. The oil projections in Table 3.2.12 are from AGA's 1981 forecast, NEPOOL's 1982 and 1983 forecasts, and an AD Little 1981 forecast. The coal price projections are from NEPOOL 1982 and 1983 forecasts.

Tables 3.2.14 and 3.2.15 present those projections that are available only in real terms. These are from AGA and the DOE National Energy Policy Plan (NEPP) projections. While these forecasts are difficult to interpret in nominal terms, it is clear that DOE expected oil prices to rise much faster than inflation, and that even the later AGA forecasts expected oil prices to rise somewhat faster than inflation. All of the forecasts in Table 3.2.15 expected coal prices to rise faster than inflation.

The nominal oil-price forecasts that were available in 1981 are generally quite consistent with the 9.4 cent/kWh expectation for 1989 cited in Appendix B of the MRI Contractual Request.

The same point is made by Figure 3.2.11, excerpted from a 1985 summary of oil price forecasts made in 1981-85 for 1990. The summary was prepared by Professor William Hogan of Harvard's Kennedy School. Note that these prices are for crude oil; residual is usually less expensive than crude.

In June 1983, long after the signing of the NESWC Service Agreements between the NESWC communities and MRI, and two months after the issuance of the Official Statement, some 68 participants in the International Energy Workshop responded to a poll on their expectations for the world crude oil price in 1990. The participants seem to have relied primarily on studies performed by their various organizations in 1982 and 1983. The forecasts, stated as a percentage of real 1980 prices, ranged from 71% to 223%, with an average of 111%. The median estimate (i.e., the value for which half of the projections were higher and half lower) was 110%. The actual ratio of 1989 crude oil price to 1980 crude oil price, in constant dollars, was 36%.[18] Thus, even the most cautious of the 68 forecasters expected the real 1990 oil price to be 97% higher than it actually was. The nominal price differentials were probably even larger; as noted

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18/ This ratio is from EIA's Annual Energy Review 1989, Table 68. The 1980 imported oil price was $33.89/bbl ($39.54 in 1982$); the 1989 price was $18.07 ($14.31 in 1982$). Actual 1990 prices are not yet available from most sources. Due to the rapid fluctuation in costs during the year, 1990 "average" prices are not very meaningful. In early 1990, and again by April 1991, crude prices were similar to 1989 prices.

above, inflation was generally expected to be higher than the levels which have occurred.

Figure 3.2.12 shows the distribution of the price estimates in the IEW poll. Attachment MRI-PLC-3 is the original article describing the poll.

Figure 3.2.13, taken from a later article on the IEW polls, summarizes the 1981, 1983, 1985, and 1986 polls. The projected oil price ratio for 1990 fell steadily over this period, from about 140% in 1981 to the 71% value in 1986. Nonetheless, oil prices were consistently expected to grow over time.

3.2.2 New England utility forecasts

New England utilities generally accepted the national consensus on oil prices. I have assembled a few examples, from NEPOOL Generation Task Force (GTF) projections used in planning studies, and from utility submittals in regulatory proceedings.

Table 3.2.12 shows the only official NEPOOL oil price forecasts I was able to identify for the relevant period. The NEPOOL/GTF projection of 3/82 projected a 1989 cost of about $12/MMBTU for high-sulfur oil, as is used at Brayton Point 4 and Salem Harbor 4. The cost of the medium-sulfur oil used at Manchester St. and South St. is even higher. By late 1983, the expected price of oil in 1989 had fallen, but was still over $7/MMBTU.

Similarly, Table 3.2.13 shows the NEPOOL coal price forecasts from March 1982 and November 1983. In 1982, cost of coal for the Brayton Point and Salem Harbor coal plants was expected to be about $5/MMBTU in 1990; that expectation was still over $4/MMBTU late in 1983.

In its analyses for DPU 19494, concerning the need for the Pilgrim nuclear power plant, Boston Edison filed oil price projections developed by Arthur D. Little (ADL). That testimony was filed in late 1978 or early 1979. The ADL projection for 2.2% sulfur oil delivered to New England utilities would be equivalent to about $9/MMBTU by 1990.[19]

In early 1980, the Massachusetts Municipal Wholesale Electric Company (MMWEC) filed for approval of Seabrook financing with the DPU. MMWEC assumed 9% annual escalation from the oil prices of 11/79 or 5/80. I have not located the base price assumptions, but average 1980 NEPCo residual oil prices were $3.46, implying 1990 price of $8.19/MMBTU.

In February 1980, Central Maine Power Company projected 10% oil price escalation and a 1988 oil price of 11.66¢/kWh for its

19/ The ADL forecast was in real terms. I have assumed the 7.4% inflation rate used in the DOE oil forecast in 1979.

existing oil-fired plants. By 1990, the cost of oil-fired electricity would be 14.1¢/kWh.[20]

In 1981, Boston Edison requested in Docket DPU 911 approval of a purchase of power from New Brunswick's Point Lepreau nuclear power plant. BECo forecast an oil price of $32/barrel in 1982, escalating at 11.4% annually to $76/barrel in 1990. These prices are equivalent to about $5.20/MMBTU and $12.25/MMBTU, respectively. Even the "pessimistic" (i.e., low-oil-price) forecast assumed a price of $30/bbl (or $4.85/MMBTU) in 1982 and an annual escalation of 7%, implying $8.31/MMBTU in 1990.

In July 1982, Commonwealth Gas filed the testimony of Mary M. Menino of ADL in DPU 1120, a general rate case. ADL projected 1990 base crude oil prices of $12.51/MMBTU, as tabulated in Table 3.2.12. Figure 3.2.14 shows the ADL base forecasts, ADL's confidence limits on its forecast, and the actual price of oil. I added the actual price of oil and the notes to Menino's exhibit. The confidence intervals reflect ADL's estimates of the probabilities of oil prices further from the reference progression. For example, for 1990, ADL believed that the most likely price was $41/bbl in 1980$, that the probability of the price falling below $31 was 30%, and that the probability of the price being below $24 was only 5%. The actual price of crude oil

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20/ My immediate source for this data is my testimony in Maine Public Utilities Commission Docket 84-120, which reviewed the prudence of CMP's investment in the Pilgrim nuclear plant.

in 1990 was about $15 in 1981$, about 40% lower than the 95% confidence limit. ADL would apparently have assigned a probability near zero to the prices which have actually occurred.

3.2.3 Regulatory decisions

Regulators also generally expected rising oil prices. I have collected evidence of this from the DPU orders in the three dockets cited in the previous section, and from the California Energy Commission. The order of the three DPU dockets is different from the order in the previous section; the testimony in DPU 19494 was filed prior to that in DPU 20248, but the order was issued sooner in the latter case.

DPU 20248, 2/6/81: The DPU refers repeatedly to "today's rising oil prices" (p. 15), the insecurity of oil supplies, and their 1974 conclusion that non-oil sources are important (18076, p.3). The DPU states that "...oil prices have continued to rise at an intolerable rate." (p. 16)

The DPU accepted MMWEC's fuel cost projections, and states "we find the escalation rate and the base prices reasonable in themselves; if anything, the escalation rate is too conservative," i.e., low (p. 50). In explaining this conclusion, the DPU noted that average oil price escalation was 30% between 1968 and 1977. The DPU states (p. 27) that neither the Attorney

General nor the other public-interest intervenor contested the reasonableness of the economic inputs to MMWEC's model.

DPU 19494, 9/22/81: The DPU examined whether the "oil substitution standard" would justify building Pilgrim 2. The question was framed in terms of rate levels with and without Pilgrim (p. 15). The clear assumption is that the alternative to Pilgrim is burning more oil on the margin. The DPU cites DPU 20248, invoking similar concerns about reliance on oil.

The DPU accepted BECo's fuel price forecasts, and stated that "There is one assumption in the Staszesky [BECo] exhibits which significantly understates the economic feasibility of Pilgrim II, the price of oil."

DPU 911, 11/23/81: The DPU approved BECo's purchase of power from the Point Lepreau nuclear unit, and accepted BECo's assumptions concerning fuel oil costs.

For comparison, it is interesting to note that the California Energy Commission 1981 Biennial Report projected crude oil prices of about $11/MMBTU in 1985, $17/MMBTU in 1990, and $43/MMBTU by 2000. The graph from which these assumptions are taken is reproduced as Figure 3.2.15.

3.3 Avoided-cost Projections in the Late 1970s and Early 1980s

The high projections of fossil fuel prices in the late 1970s and early 1980s were reflected in high projections of avoided costs.

To the best of my recollection, every New England utility I queried in the late 1970s and early 1980s thought oil would be the marginal fuel on its system and on the NEPOOL system for the foreseeable future.

The actual mix of marginal costs for NEPCo own-load dispatch would be primarily high-sulfur and medium-sulfur residual (#6) oil at heat rates ranging from slightly below 10,000 BTU/kWh to over 11,000; a small amount of more expensive distillate (#2) oil at worse heat rates (roughly 12,000-16,000); and some coal.

3.3.1 Expectations for incremental energy costs

I have located a number of early-1980s vintage forecasts of incremental energy costs or comparable values. These include projections of NEPCo incremental energy costs produced specifically for the NESWC project and forecasts of avoided costs for other Massachusetts utilities.

The MITRE study, which seems to have been prepared in January or February of 1981, assumes 10% annual escalation of the NEPCo incremental energy rate from 1/1/81 throughout the project life. The starting point was apparently a purchase price of 5¢/kWh, or an incremental energy rate of 5.56¢/kWh. By mid-1990, MITRE would have projected incremental energy costs of 13.7¢/kWh. MITRE is a major consulting firm which has done a fair amount of work for DOE and utilities.

A validation review of the MITRE report by Gershman, Brickner and Bratton, Inc. (GBB), dated 8/4/81, observed that "NEPCo's average power costs have tripled in two years." The report projected NEPCo's average cost of power and off-peak power costs would decline as more oil-fired generation was converted to coal. GBB noted, "On balance, however, the peak power will continue to be oil-based for a long time, and on-peak incremental power cost increases are expected to outstrip inflation." Referring to the on-peak and off-peak factors, GBB observed that "The multipliers have shown consistent increase . . . over the last three years." In other words, although coal helped to keep down the <u>average</u> cost of power, it had little effect on the <u>incremental</u> cost, resulting in rising factors over time. The report concluded that "MITRE's estimates of electricity values appear conservative, as a 10% rate of increase or more is likely when the incremental cost multipliers are considered."

Appendix A to the Offering Statement is the Consulting Engineers' Feasibility Report, prepared by Roy F. Weston, Inc. and dated 4/18/83. Weston referred to the "recent anomalous drop in oil prices" (p. A-38) and projected that NEPCo incremental fuel costs would rise from an effective level of 5.2¢/kWh in

January, 1983.[21] Weston assumed in the base case a constant 9% annual growth rate in the incremental fuel cost, bringing it to 10.21¢/kWh by 1990 (p. A-43). A "comparison" case assumed incremental fuel costs would rise at 2% above inflation, or 9.14% to 1986 and 10.16% thereafter, bringing 1990 incremental fuel cost to 10.63¢/kWh. A high-price sensitivity case assumed incremental fuel cost escalation of 11%, for a 1990 incremental energy rate of 11.78¢/kWh (pp. A-50, A-69, and A-70). A low-price case assumed incremental fuel cost escalation of 5% to 1986, and 7% thereafter, for 8.22¢/kWh in 1990 (pp. A-50, A-71, and A-72).

Massachusetts utilities generally did not publish forecasts of long-run avoided costs in the early 1980s. The first such forecast I have found is from Commonwealth Electric. Table 3.3.1 shows this projection of avoided costs, which was filed with the DPU in January of 1983, almost two years after the signing of the Service Agreement. Even with the lower oil price projections current in 1983 (compared to 1985) Commonwealth Electric expected avoided energy costs of 8.9¢/kWh in 1989 and 10¢/kWh in 1990.

3.4 Recent estimates of NEPCo incremental costs, at previously expected fuel prices

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21/ Weston notes that a couple months earlier, it had been assuming a quick return to a rising trend from the January 1982 incremental cost level of 5.8¢/kWh.

3.4.1 Derivation of the formula

Attachment MRI-PLC-2 contains data on NEPCo avoided costs from the MECo filings with the DPU. For each of a number of proposed contracts with QFs, starting in 1987, MECo filed projected avoided costs to determine whether the proposed purchase was cost-effective. The avoided energy costs for the first few years of each contract were determined in essentially the same manner as are the incremental energy costs in the MRI contract; the NEPCo production costing model is run twice, with different levels of load, and the difference in cost is divided by the difference in energy output to determine the avoided cost per kWh.[22] NEPCo performed these computations for base, high, and low fuel-price cases, in which oil prices changed but coal prices did not.

Since NEPCo does not make its avoided cost model, or the detailed inputs and outputs, available to other parties, I estimated the mix of fuel sources from publicly available NEPCo forecasts of fuel prices and avoided costs. I used regression analysis to determine the mix of fuels which, at NEPCo's expected

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22/ After the first few years, the MECo avoided-cost filings differ from the NEPCo incremental energy cost computation in that MECo (following DPU instructions) computes the net savings of avoiding a new generating unit, including the avoided fixed costs of the unit (but also including the lost fuel savings from the unit). Thus, the MECo avoided-cost projections are comparable to forecasts of the NEPCo incremental energy cost only for the first few years of the projections, until a generation addition would be avoided.

fuel prices, would produce the expected avoided costs. Specifically, I used oil prices (for 2.2% #6 oil), coal prices, and a time-trend variable to estimate the forecast avoided cost. For the 1988 analyses, MECo had avoided-cost estimates for five years (1987-91) prior to the in-service date of its first avoidable unit, and for three fuel-price forecasts (low, base, and high), giving a total of 15 data points. The regression analysis that best fit the data was:

$$AEC = (8950*O + 2776*C)/10000 - 0.054*T,$$

where

AEC = avoided energy cost, in ¢/kWh

O = price of 2.2% sulfur #6 oil, in \$/MMBTU

C = price of NEPCo coal, in \$/MMBTU

T = a time trend, starting at -2 in 1987, rising to 2 in 1991.

The regression equation explains 98.7% of the variation in the data. In other words, the regression fits the data very well.

3.4.2 Demonstration that the formula accurately explains reported NEPCo incremental costs

Table 3.4.1 tests the accuracy of the regression equation I derived for NEPCo's incremental energy costs. For each year, 1985-1989, the table shows NEPCo's actual fuel prices, the incremental energy costs predicted by the equation, and the actual incremental energy costs used in determining MRI's electric energy revenues.[23] This "backcast" is quite accurate, especially considering that the regression did not include data for 1985 and 1986. It is also important to recall that the reported incremental energy costs are the result of applying factors computed for <u>forecast</u> costs to actual average costs, while the regression equation is evaluated using actual fuel costs.

3.4.3 Estimates

Based on the regression analysis discussed above, Table 3.4.2 estimates the NEPCo incremental cost that would have resulted in each year 1985-90 had the fuel prices forecast in the early 1980s actually occurred. I have included DOE/EIA fuel price forecasts for 1980-83, DRI fuel price forecasts for Winter 1980/81 and Spring 1982, Wharton forecasts from 1980-83, and NEPOOL forecasts from 1982 and 1983. These fuel price forecasts generally span the range of forecasts I have identified from the early 1980s. I have adjusted the crude oil forecasts to reflect New England high-sulfur #6 oil prices by multiplying the forecast

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<u>23</u>/ The 1988 fuel prices are from the NEEI fuel-price forecast published late in that year. The NEPCo reports to FERC, the source for the fuel-price data in other years, do not differentiate between coal and oil prices.

crude oil price by the actual ratio of NEPCo #6 oil price to crude oil for the particular year. I have similarly adjusted the coal price forecasts.

The data indicate that fuel price forecasts in the period 1980-81 generally support the level of avoided costs expected in the Weston study, which were in turn lower than the estimates from the 1981 studies by MITRE and Gershman. Even coal prices were often expected to be higher than the incremental costs actually used by NEPCo in determining payments to MRI. By mid-to-late 1983, expectations for future fuel prices had fallen considerably, but were still 2-3 times the eventual avoided-cost payments.

3.5 Current Expectations for the Future

The discrepancies between the fuel cost expectations of the early 1980s and the actual costs of fossil fuels are expected to continue. Table 3.5.1 compares forecasts of residual oil prices published in the 1980-82 period by DRI and NEPOOL with the most recent forecasts by DRI, NEPOOL, and NEPCo.[24] In each case, I have taken the old forecast closest to the signing of the Service Agreement and the most recent forecast I have available. Figure 3.5.1 displays the same information graphically. The gap between the prices expected in the early 1980s and those expected today

24/ I do not have early oil price forecasts from NEPCo.

grows over time. This is particularly striking, in that the recent DRI, NEPOOL, and NEPCo forecasts are for high-sulfur residual, which is somewhat less expensive than the aggregate residual oil represented in the older DRI and AGA forecasts. The shortfall in energy revenues, compared to projections in the early 1980s, is therefore a continuing phenomenon.

4. CONCLUSIONS

The entire discrepancy between the projected and actual energy purchase rates can be explained by the difference between fuel prices generally forecast in 1980-81 and actual fuel prices. Not only did fuel prices not rise as fast as expected, they actually fell between 1981 and 1989.

Fuel-cost projections widely accepted in 1981 would have produced a NEPCo incremental energy rate of 12-17¢/kWh in 1990. Thus, the incremental energy rates projected for the project by MITRE, Gershman, and Weston, ranging from 10¢/kWh to at least 14¢/kWh, were representative of the rates foreseen at the time. The actual rates, roughly 3¢/kWh for 1986-90, were not foreseen in 1980 or 1981, or even as late as 1983.

Table 4.1 computes the reduction in energy revenue between the revenues expected in the Weston Report and the actual revenues realized by MRI. I assume that the NEPCo energy purchase rises at 5% annually, 1991-2005; this approximates NEPCo's current fuel price assumptions. I use MRI's actual energy sales for 1986-1990, and assume that their projected sales for the next 5 years are applicable through the year 2005. The total revenue losses to MRI during the period 1986-1990 were $6.2 million, with expected annual losses of approximately $3.8 million (depending on future fuel prices) for the future. The reduction in revenues from the MITRE and Gershman estimates of 1981 vintage would be even larger.

I, Paul Chernick, do hereby certify that I have read the foregoing testimony and further certify that said testimony is true and correct. Signed under the pains and penalties of perjury this 13th day of May, 1991.

Paul Chernick

Sign here

Figure 2.3.1 NEES Actual Energy Mix
1981-1990

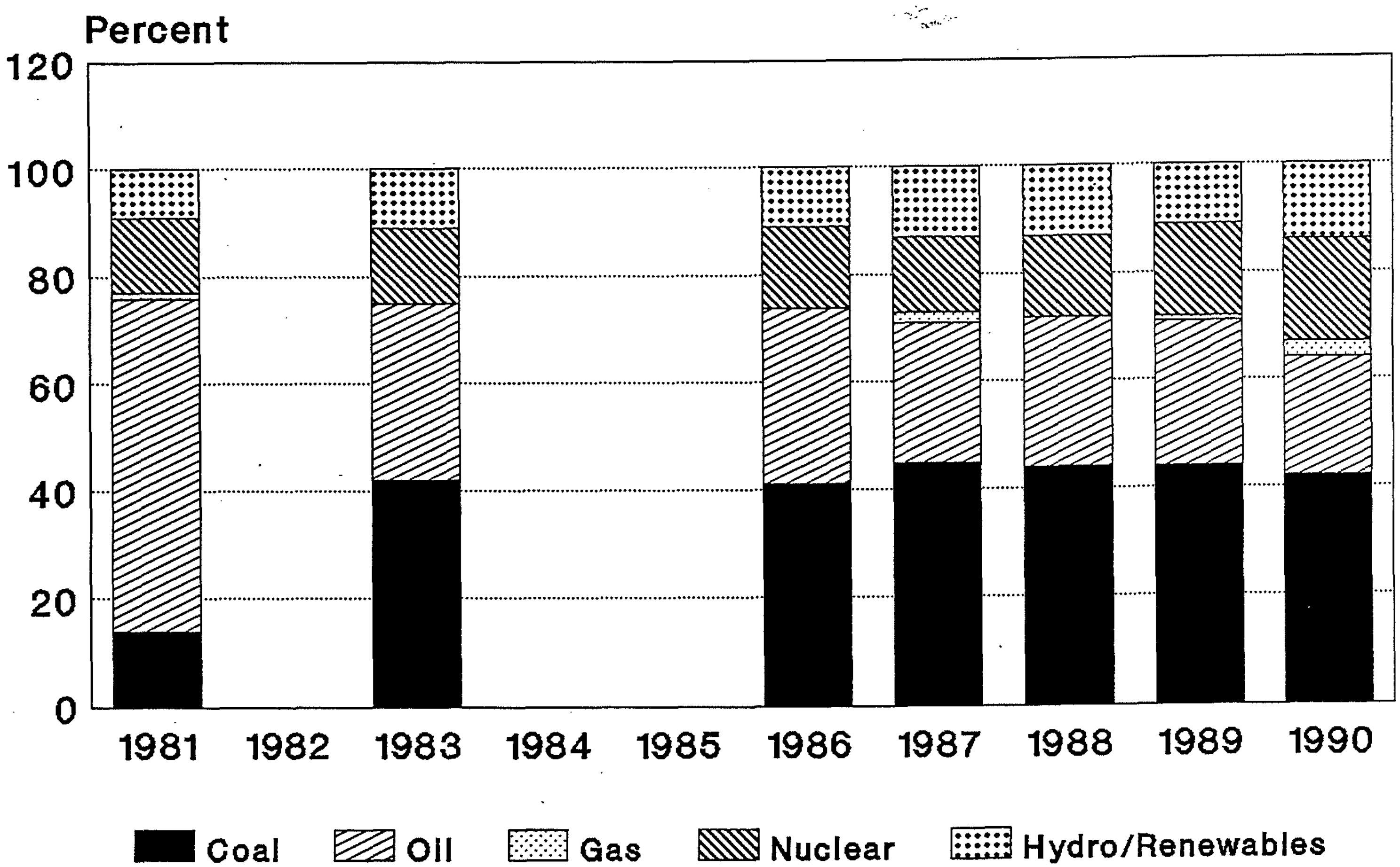


Table 2.4.1
NEP Fuel Adjustment Charge and Incremental Fuel Rate

Year		Fuel Adjustment Charge $/kWh	On-Peak Multiplier	Off-Peak Multiplier	Average Multiplier	Average Incremental Fuel Cost $/kWh
[1]		[2]	[3]	[4]	[5]	[6]
1977		0.0168	1.45	1.25	1.34	0.0225
1978		0.0152	1.45	1.25	1.34	0.0205
1979		0.0210	1.58	1.29	1.42	0.0298
1980		0.0293	1.63	1.33	1.47	0.0430
1981		0.0361	1.85	1.52	1.67	0.0603
1982		0.0267	2.18	1.68	1.91	0.0509
1983	[7]	0.0287	2.00	1.61	1.79	0.0514
1984	[7]	0.0293	N/A	N/A	N/A	N/A
1985	[8]	0.0241	2.30	1.64	1.94	0.0469
1986	[9]	0.0194	2.03	1.47	1.73	0.0334
1987		0.0190	1.82	1.36	1.57	0.0298
1988		0.0201	1.90	1.30	1.57	0.0316
1989		0.0205	1.83	1.19	1.48	0.0304
1990	[7]	0.0228	1.70	1.25	1.46	0.0332

Notes:

N/A: Not available.

[2]: 1977-82: From Weston. Northeast Massachusetts Resource Recovery Project: Consulting Engineers' Feasibility Report (1983). Page A-40.
1987-89: From NEPCo.
1984-86, 90: From MECo, as noted below.

[3]: 1977-83: From Weston (1983), page A-40.
1985-90: From NEPCo.

[4]: 1977-83: From Weston (1983), page A-40.
1985-90: From NEPCo.

[5]: Based on 4000 hours On-Peak and 4760 hours Off-Peak

[6]: Fuel Adjustment Charge [2] * Average Multiplier [5]

[7]: Based on MECo FAF, as supplied by Massachusetts D.P.U.

[8]: Based on MECo FAF, as supplied by Massachusetts D.P.U. NEPCo FAC rates were unavailable for March, April and December of 1985. However, the NEPCo average for the other nine months was .0238.

[9]: Based on MECo FAF, as supplied by Massachusetts D.P.U. NEPCo FAC was unavailble for January of 1986. However, the NEPCo average for the other eleven months was .0183, and a steady drop in FAC rate was evident in early 1986.

Table 2.4.2
Actual NEPCo, New England, and U.S. Oil Prices

	Current $/MMBtu					Ratios		
Year [1]	EIA Imported Crude [2]	EIA #6 Oil >1% S [3]	EIA #2 Oil [4]	ECNE [5]	NEPCo [6]	NEPCo: EIA Crude [7]	NEPCo: EIA #6 [8]	NEPCo: ECNE [9]
1977	2.34			2.13	2.08	0.89		0.98
1978	2.35	1.83	2.86	2.00	1.82	0.77	0.99	0.91
1979	3.50	2.59	3.69	2.75	2.53	0.72	0.98	0.92
1980	5.47	3.49	5.63	3.98	3.46	0.63	0.99	0.87
1981	5.98	4.49	6.53	5.12	4.56	0.76	1.02	0.89
1982	5.41	4.07	6.46	4.63	4.06	0.75	1.00	0.88
1983	4.73	4.07	6.54	4.43	4.08	0.86	1.00	0.92
1984	4.66	4.39	6.54	4.72	4.44	0.95	1.01	0.94
1985	4.35	3.88	6.06	4.28	3.38	0.78	0.87	0.79
1986	2.26	2.11	4.00	2.51	2.25	1.00	1.06	0.90
1987	2.92	2.64	4.15	2.82	2.51	0.86	0.95	0.89
1988	2.35	2.00	3.89	2.37	1.92	0.82	0.96	0.81
1989	2.91	2.33	4.22	2.62	2.39	0.82	1.03	0.91
1990	3.52				2.93			

Notes:
[2]: From Annual Energy Review 1989, Table 68. 1990 figure provided telephonically by EIA. Heat content is assumed to be 6.2 MMBtu/bbl.
[3]: From Annual Energy Review 1989, Table 69. Figures represent price to end users and exclude taxes. Heat contnet assumed to be 6.3 MMBtu/bbl.
[4]: From Annual Energy Review 1989, Table 69. Figures represent price to end users and exclude taxes. Heat contnet assumed to be 5.88 MMBtu/bbl.
[5]: 1979-89 from Electric Utility Industry in New England Statistical Bulletin 1989, Tables, p. 12.
1976-77 from Electric Utility Industry in New England Statistical Bulletin 1987, Tables, p. 12.
Figures are for all New England electric utilities, and are based on actual heat contents from 6.21 to 6.31 MMBtu/bbl. 1989 figure is an estimate.
[6]: From NEPCo's FERC filings. Figures represent cost per bbl burned divided by the given heat content (from 5.78 to 6.31 MMBtu/bbl), and are a weighted average of Brayton Point and Salem Harbor plants. These unit prices do not always agree with those reported.
[7]: [6]/[2]
[8]: [6]/[3]
[9]: [6]/[5]

Table 2.4.3
Actual NEPCo, New England, and U.S. Coal Prices

	Current $/MMBtu				Ratios		
Year [1]	EIA Minemouth [2]	EIA Delivered [3]	ECNE [4]	NEPCo [5]	NEPCo: EIA Minemouth [6]	NEPCo: EIA CIF [7]	NEPCo: ECNE [8]
1977	0.92	0.95	1.32				
1978	1.02	1.12	1.50				
1979	1.11	1.22	1.59	2.06	1.86	1.69	1.30
1980	1.14	1.35	1.68	1.85	1.62	1.37	1.10
1981	1.25	1.53	2.14	1.44	1.15	0.94	0.67
1982	1.28	1.65	2.47	2.54	1.98	1.54	1.03
1983	1.22	1.66	2.36	2.35	1.92	1.42	1.00
1984	1.21	1.66	2.20	2.15	1.78	1.30	0.98
1985	1.20	1.65	2.18	1.98	1.65	1.20	0.91
1986	1.12	1.58	2.05	1.80	1.60	1.14	0.88
1987	1.09	1.51	1.95	1.60	1.47	1.06	0.82
1988	1.05	1.47	1.94	1.59	1.51	1.08	0.82
1989	1.09	1.44	1.75	1.57	1.44	1.09	0.90
1990				1.71			

Notes:
[2]: From Annual Energy Review 1989, Table 86. Prices are free on board (FOB) mines. Heat content is from AER 1989, Table A5 for Electric Utilities.
[3]: From Annual Energy Review 1989, Table 86. Prices include cost, insurance, and freight (CIF) for electric utility plants.
[4]: 1979-89 from Electric Utility Industry in New England Statistical Bulletin 1989, Tables, p. 12.
1976-77 from Electric Utility Industry in New England Statistical Bulletin 1987, Tables, p. 12.
Figures are for all New England electric utilities, and are based on actual heat contents. 1989 figure is an estimate.
[5]: From NEPCo's FERC filings. Figures represent the cost per ton of coal burned divided by the given heat content, and represent a weighted average of the Brayton Point and Salem Harbor plants. These unit prices do not always agree with those reported.
[6]: [5]/[2]
[7]: [5]/[3]
[8]: [5]/[4]

Table 3.1.1
Inflation Expectations for the 1980's

Source:	Date:		Projection:
NEPOOL Generation Task Force	March 1982	[1]	8%
Weston	April 1983	[2]	7% 1983–86 8% thereafter implies 7.6% average
Gershman	August 1981	[3]	13% for 1980–85 10% thereafter implies 11.5% average
American Gas Association	November 1981	[4]	8.2%
MITRE	October 1979	[5]	7%
	April 1980	[6]	7–9%
	Jan/Feb 1981	[7]	10%
Data Resources, Inc.	Winter 1979/80	[8]	7.5%
	Winter 1980/81	[8]	8.0%
	Spring 1982	[8]	7.9%
	Winter 1982/83	[8]	6.4%
Department of Energy	1980	[9]	7.9%
	1981	[9]	7.4%
	1982	[9]	6.1%
	1983	[9]	5.5%

Notes:
Projections are averages for those years remaining in the decade unless otherwise stated.

[1]: NEPOOL Planning Committee and Generation Task Force. Summary of GTF Long Range Study Assumptions. March 1982. Exhibit 4.

[2]: Weston. Northeast Massachusetts Resource Recovery Project: Consulting Engineers' Feasibility Report April 1983. Page A–49.

[3]: Gershman, Brickner & Bratton, Inc. Cost Validation of the NESWC Resource Recovery Project, July 21, 1981. Page 118077, e.g.

[4]: American Gas Association. Consumer Impact of Indefinite Gas Price Escalator Clauses Under Alternative Decontrol Plans, November 1983. Table 1.

[5]: MITRE Corporation, METREK Division. Letter from Ahti E. Autio to Alden Cousins of the Massachusetts Department of Environmental Management. October 19, 1979.

[6]: MITRE Corporation, METREK Division. Letter from Ahti E. Autio to Terrence J. Geoghegan of Massachusetts Executive Office of Environmental Affairs. Table II. April 29, 1980.

[7]: MITRE. Concept of Estimated Net Disposal Costs to Communities, January or February 1981. Page 118224.

[8]: Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector – years indicated, GNP deflator.

[9]: Energy Information Agency (Eugene Reiser) excerpted from Annual Energy Outlook – years indicated.

Table 3.2.1
DRI Crude Oil Price Forecasts

	Nominal $/MMBtu			
Year [1]	Winter 1979/80 [2]	Winter 1980/81 [3]	Spring 1982 [4]	Winter 1982/83 [5]
1977	2.3			
1978	2.4	2.4		
1979	3.4	3.3		
1980	5.4	5.3	4.6	
1981	7.0	7.1	6.1	6.1
1982	8.2	8.4	5.7	5.6
1983	9.1	9.4	5.8	5.5
1984	10.0	10.4	6.4	5.9
1985	11.1	11.5	7.1	6.4
1986	12.2	12.9	8.0	7.1
1987	13.5	14.5	9.1	7.9
1988	14.8	16.3	10.3	8.7
1989	16.3	18.3	11.6	9.7
1990	18.0	20.5	13.1	10.7

Notes:

[2]: Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, 1979/80.
1977 price was taken from EIA reported actual world oil price, and adjusted to reflect DRI's forecasted rates of change for refiner acquisition cost.

[3]: Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, 1980/1.
1978 price was taken from EIA reported actual world oil price, and adjusted to reflect DRI's forecasted rates of change for refiner acquisition cost.

[4]: Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, Spring 1982.
Prices represent refiner acquisition cost. 1986-1989 data have been interpolated at a constant rate of escalation.

[5]: Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, Winter 1982/3.
Prices represent refiner acquisition cost. 1986-1989 data have been interpolated at a constant rate of escalation.

Table 3.2.2
DRI Residual Oil Price Forecasts

	Nominal $/MMBtu			
Year	Winter 1979/80	Winter 1980/81	Spring 1982	Winter 1982/83
[1]	[2]	[3]	[4]	[5]
1978	1.8	1.8		
1979	2.9	2.7		
1980	4.3	3.8	4.2	
1981	5.4	4.8	5.1	5.2
1982	6.4	5.8	4.8	4.7
1983	7.7	6.4	5.0	4.7
1984	9.4	7.9	5.5	5.1
1985	11.4	9.7	6.1	5.6
1986	12.4	10.9	6.9	6.2
1987	13.6	12.1	7.7	6.8
1988	14.9	13.6	8.7	7.4
1989	16.4	15.2	9.8	8.2
1990	18.0	17.0	11.0	9.0

Notes:

[2]: Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, Winter 1979/80.
1978 price was taken from EIA's reported actuals for #6 residual oil (having greater than 1% sulfur) to end users (excluding taxes), and then escalated according to DRI's forecasted rates of change.

[3]: Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, Winter 1980/1.
1978 price was taken from EIA's reported actuals for #6 residual oil (having greater than 1% sulfur) to end users (excluding taxes), and then escalated according to DRI's forecasted rates of change.

[4]: Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, Spring 1982.
Prices are for "residual oil industrial." 1986-1989 data have been interpolated at a constant rate of escalation.

[5]: Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, Winter 1982/3.
Prices are for "residual oil industrial." 1986-1989 data have been interpolated at a constant rate of escalation.

Table 3.2.3
DRI Delivered Coal Price Forecasts

	Nominal $/MMBtu			
Year	Winter 1979/80	Winter 1980/81	Spring 1982	Winter 1982/83
[1]	[2]	[3]	[4]	[5]
1977	1.0			
1978	1.0	1.1		
1979	1.2	1.3		
1980	1.3	1.5	1.4	
1981	1.5	1.7	1.5	1.5
1982	1.7	1.9	1.7	1.7
1983	1.9	2.2	1.9	1.8
1984	2.2	2.5	2.1	1.9
1985	2.4	2.7	2.4	2.1
1986	2.7	3.0	2.7	2.3
1987	3.0	3.3	2.9	2.6
1988	3.3	3.7	3.3	2.9
1989	3.6	4.1	3.6	3.2
1990	4.0	4.5	4.0	3.6

Notes:

[2]: Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, 1979/80.
Base year price was taken from Annual Energy Review 1989 CIF coal prices (Table 86) and then adjusted according to DRI's rate of change forecasts.

[3]: Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, 1980/1.
Base year price was taken from Annual Energy Review 1989 CIF coal prices (Table 86) and then adjusted according to DRI's rate of change forecasts.

[4]: Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, Spring 1982.
Prices are for delivered/contract coal. 1986-1989 data have been interpolated at a constant rate of escalation.

[5]: Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, Winter 1982/3.
Prices are for delivered/contract coal. 1986-1989 data have been interpolated at a constant rate of escalation.

Table 3.2.4
Wharton Crude Oil Price Forecasts

	Nominal $/MMBtu			
	1980	1981	1982	1983
Year	Forecast	Forecast	Forecast	Forecast
[1]	[2]	[3]	[4]	[5]
1980	4.87			
1981	5.56	5.73		
1982	6.27	6.37	5.43	
1983	7.02	7.20	5.50	4.65
1984	7.66	8.03	6.07	4.70
1985	8.67	8.84	6.85	5.13
1986	9.10	9.72	7.66	5.69
1987	9.92	10.69	8.39	6.32
1988	10.81	11.76	9.11	6.83
1989	11.79	12.94	9.84	7.30
1990	12.85	14.23	10.62	7.74

Notes:
[2],[3],[4],[5]:
Wharton Econometric Forecasting Associates. Wharton Annual Forecasting Model, Energy Price Forecasts, 1980, 1981, 1982, 1983, respectively. Forecasts are for imported oil.

Table 3.2.5
Wharton Coal Price Forecasts

	Nominal $/MMBtu			
Year	1980 Forecast	1981 Forecast	1982 Forecast	1983 Forecast
[1]	[2]	[3]	[4]	[5]
1980	1.42			
1981	1.59	1.46		
1982	1.74	1.56	1.27	
1983	1.87	1.75	1.37	1.33
1984	2.02	1.90	1.48	1.40
1985	2.18	2.07	1.60	1.50
1986	2.33	2.24	1.71	1.59
1987	2.50	2.42	1.83	1.68
1988	2.72	2.65	2.00	1.79
1989	2.93	2.89	2.14	1.90
1990	3.15	3.13	2.29	2.00

Notes:
[2],[3],[4],[5]:
Wharton Econometric Forecasting Associates. Wharton Annual Forecasting Model, Energy Price Forecasts, 1980, 1981, 1982, 1983, respectively.
Forecasts are for domestic coal.

Table 3.2.6
EIA Base Crude Price Forecasts

	Nominal $/MMBtu			
Year [1]	1980 Forecast [2]	1981 Forecast [3]	1982 Forecast [4]	1983 Forecast [5]
1980	5.48	5.48		
1981				
1982			5.42	
1983			5.00	4.73
1984			4.68	4.68
1985	9.84	7.90	4.68	4.68
1986	10.82	9.12	5.48	4.68
1987	11.89	10.51	6.77	5.32
1988	13.08	12.13	7.74	6.29
1989	14.38	13.99	8.71	7.42
1990	15.81	16.13	9.52	8.55

Notes:
All forecasts are based on World Oil Price, and assume a heat content of 6.2 MMBtu/barrel.

[2]: Energy Information Administration, from Annual Energy Outlook 1980. 1986-9 data have been interpolated at a constant rate of escalation.
[3]: Energy Information Administration, from Annual Energy Outlook 1981. 1986-9 data have been interpolated at a constant rate of escalation.
[4]: Energy Information Administration, from Annual Energy Outlook 1982.
[5]: Energy Information Administration, from Annual Energy Outlook 1983.

Table 3.2.7
EIA Low Crude Price Forecasts

	Nominal $/MMBtu			
Year [1]	1980 Forecast [2]	1981 Forecast [3]	1982 Forecast [4]	1983 Forecast [5]
1980	5.48	5.48		
1981				
1982			5.42	
1983			4.68	4.73
1984			4.03	4.03
1985	8.48	6.13	3.87	4.03
1986	9.14	6.96	4.19	4.19
1987	9.86	7.91	4.68	4.35
1988	10.62	8.99	5.48	5.00
1989	11.45	10.22	6.29	5.81
1990	12.34	11.61	7.26	6.77

Notes:
All forecasts are based on World Oil Price, and assume a heat content of 6.2 MMBtu/barrel.

[2]: Energy Information Administration, from Annual Energy Outlook 1980. 1986-9 data have been interpolated at a constant rate of escalation.

[3]: Energy Information Administration, from Annual Energy Outlook 1981. 1986-9 data have been interpolated at a constant rate of escalation.

[4]: Energy Information Administration, from Annual Energy Outlook 1982.

[5]: Energy Information Administration, from Annual Energy Outlook 1983.

Table 3.2.8
EIA High Crude Price Forecasts

	Nominal $/MMBtu			
Year [1]	1980 Forecast [2]	1981 Forecast [3]	1982 Forecast [4]	1983 Forecast [5]
1980	5.48	5.48		
1981				
1982			5.42	
1983			5.32	4.73
1984			5.32	5.00
1985	11.37	9.03	6.45	5.32
1986	12.58	10.57	7.58	5.81
1987	13.93	12.37	8.71	6.61
1988	15.41	14.48	9.68	7.90
1989	17.05	16.95	10.81	9.19
1990	18.87	19.84	12.42	10.65

Notes:
All forecasts are based on World Oil Price, and assume a heat content of 6.2 MMBtu/barrel.
[2]: Energy Information Administration, from Annual Energy Outlook 1980. 1986-9 data have been interpolated at a constant rate of escalation.
[3]: Energy Information Administration, from Annual Energy Outlook 1981. 1986-9 data have been interpolated at a constant rate of escalation.
[4]: Energy Information Administration, from Annual Energy Outlook 1982.
[5]: Energy Information Administration, from Annual Energy Outlook 1983.

Table 3.2.9
EIA Base Case Coal Price Projections

	Nominal $/MMBtu			
Year [1]	1980 Forecast [2]	1981 Forecast [3]	1982 Forecast [4]	1983 Forecast [5]
1978	1.03			
1979		1.22		
1980				
1981				
1982			1.43	
1983				1.33
1984				
1985	2.30	2.20	1.68	1.54
1986	2.49	2.37	1.81	1.64
1987	2.70	2.55	1.94	1.75
1988	2.92	2.74	2.08	1.86
1989	3.16	2.96	2.24	1.99
1990	3.42	3.18	2.40	2.12

Notes:
[2],[3],[4],[5]:

Eugene Reiser of Energy Information Administration, from Annual Energy Outlook 1980,1981,1982, and 1983, respectively.
Forecasts are as under a mid-range oil price scenario. Price is at minemouth and reflects actual heat content as reported for electric utilities in Annual Energy Review 1989, Table A5. The 1989 figure was used for 1990 calculations. 1986-89 data have been interpolated assuming a constant rate of escalation.

Table 3.2.10
EIA Low Coal Price Projections

	Nominal $/MMBtu			
Year [1]	1980 Forecast [2]	1981 Forecast [3]	1982 Forecast [4]	1983 Forecast [5]
1978	1.03			
1979		1.22		
1980				
1981				
1982			1.43	
1983				1.33
1984				
1985	2.26	2.10	1.67	1.53
1986	2.29	2.13	1.79	1.64
1987	2.31	2.15	1.92	1.75
1988	2.34	2.18	2.06	1.86
1989	2.36	2.21	2.20	1.98
1990	2.39	2.24	2.36	2.12

Notes:
[2],[3],[4],[5]:
Eugene Reiser of Energy Information Administration, from Annual Energy Outlook 1980,1981,1982, and 1983, respectively.
Forecasts are as under a low oil price scenario. Price is at minemouth and reflects actual heat content as reported for electric utilities in Annual Energy Review 1989, Table A5. The 1989 figure was used for 1990 calculations. 1986-89 data have been interpolated assuming a constant rate of escalation.

Table 3.2.11
EIA High Coal Price Projections

	Nominal $/MMBtu			
Year [1]	1980 Forecast [2]	1981 Forecast [3]	1982 Forecast [4]	1983 Forecast [5]
1978	1.03			
1979		1.22		
1980				
1981				
1982			1.43	
1983				1.33
1984				
1985	2.35	2.22	1.70	1.53
1986	2.55	2.39	1.83	1.64
1987	2.77	2.57	1.97	1.74
1988	3.00	2.76	2.12	1.86
1989	3.25	2.98	2.29	1.98
1990	3.53	3.20	2.46	2.11

Notes:
[2],[3],[4],[5]:

Eugene Reiser of Energy Information Administration, from Annual Energy Outlook 1980,1981,1982, and 1983, respectively.
Forecasts are as under a high oil price scenario. Price is at minemouth and reflects actual heat content as reported for electric utilities in Annual Energy Review 1989, Table A5. The 1989 figure was used for 1990 calculations. 1986-89 data have been interpolated assuming a constant rate of escalation.

Table 3.2.12
Various Oil Price Forecasts

	Nominal $/MMBtu				
Year	NEPOOL residual 3/82	NEPOOL residual 11/83	AGA residual 11/81	A.D. Little base case residual 1978	A.D. Little base case crude 1981
[1]	[2]	[3]	[4]	[5]	[6]
1977			1.44		
1978			1.62	2.03	
1979			2.53		
1980			3.46	2.23	
1981	5.21		5.27		5.16
1982	5.78	4.17	6.06		
1983	6.42	4.51	6.82		
1984	7.13	4.88	7.59		
1985	7.91	5.28	8.41	4.69	7.62
1986	8.78	5.72	9.32	5.34	8.41
1987	9.74	6.18	10.34	6.07	9.29
1988	10.82	6.69	11.32	6.90	10.26
1989	12.01	7.24	12.39	7.85	11.33
1990	13.33	7.83	13.48	8.93	12.51

Notes:

[2]: NEPOOL Planning Committee and Generation Task Force. Summary of GTF Long Range Study Assumptions, March 1982. Exhibits 4 and 12.
Prices are for oil containing 1.5-2.7% sulfur, and include transportation to plant.
NEPLAN/GTF assumes heat content of 6.2MMBtu/bbl.

[3]: NEPOOL Planning Committee and Generation Task Force. Summary of GTF Long Range Study Assumptions, November 1983 update. Exhibits 4 and 12 (1/83).
Prices are for oil containing 1.5-2.7% sulfur, and include transportation to plant.
NEPLAN/GTF assumes heat content of 6.2MMBtu/bbl.

[4]: American Gas Association. Consumer Impact of Indefinite Gas Price Escalator Clauses Under Alternative Decontrol Plans, Table 1. November 1983.
Prices are for industrial residual.

[5]: A. D. Little. DPU 19494 Exhibit # BE-II-400: Direct Testimony of Messrs. Messing, Turner, and Godley before the Massachusetts Department of Public Utilities.
Forecast is for delivered residual containing 2.2% sulfur, and has been adjusted from 1977 $ to reflect a 7.4% rate of annual inflation forecasted by the Department of Energy in 1979. 1986-89 data have been interpolated assuming a constant rate of escalation.

[6]: A.D. Little. DPU 1120: Prepared Direct Testimony of Mary M. Menino, on behalf of Commonwealth Gas Co. July 1, 1982. Page 6 data are from August 1981.
Central forecast is for Saudi Arabian light crude FOB Ras Tanura. 1986-89 data have been interpolated assuming a constant rate of escaltion.

Table 3.2.13
NEPOOL Coal Price Forecasts

	Nominal $/MMBtu	
	NEPOOL	NEPOOL
Year	3/82	11/83
[1]	[2]	[3]
1977		
1978		
1979		
1980		
1981	2.20	
1982	2.42	
1983	2.66	
1984	2.93	
1985	3.22	2.80
1986	3.54	3.03
1987	3.90	3.28
1988	4.29	3.56
1989	4.72	3.85
1990	5.19	4.17

Notes:

[2]: NEPOOL Planning Committee and Generation Task Force. Summary of GTF Long Range Study Assumptions, March 1982. Exhibits 4 and 12.
Prices are for coal containing 1.05-2.24% sulfur, and include transportation to plant, but not handling. NEPLAN GTF assumes a heat content of 26 MMBtu/ton.

[3]: NEPOOL Planning Committee and Generation Task Force. Summary of GTF Long Range Study Assumptions, November 1983 update. Exhibits 4 and 12 (1/83).
Prices are for coal containing 1.05-2.24% sulfur, and include transportation to plant, but not handling. NEPLAN GTF assumes a heat content of 26 MMBtu/ton.

Table 3.2.14
Various Crude Oil Price Forecasts (Real Prices)

	1982 $/MMBtu		
Year [1]	NEPP July 1981 [2]	AGA July 1982 [4]	AGA Nov. 1983 [5]
1980	5.66	5.79	
1981			
1982			5.50
1983			4.70
1984			
1985	8.07	5.30	4.74
1986	8.34	5.40	4.83
1987	8.63	5.50	4.92
1988	8.92	5.60	5.01
1989	9.23	5.70	5.11
1990	9.54	5.81	5.21

Notes:

[2]: U.S. Department of Energy, Office of Policy, Planning, and Analysis. Energy Projections to the Year 2000. July 1981. Table 3-1.
Figures are for Midrange Refiner Crude Acuisition Cost. 1986-89 data have been interpolated assuming a constant rate of escalation.

[3]: American Gas Association. TERA (Total Energy Resource Analysis Model) Analysis 82-1, Table 10. July 13, 1982.
Figures are for average refiner acquisition cost. 1986-89 data have been interpolated assuming a constant rate of escalation.

[4]: American Gas Association. TERA Analysis 82-3, Table 10. November 16, 1983.
Figures are for average refiner acquisition cost. 1986-89 data have been interpolated assuming a constant rate of escalation.

Table 3.2.15
Various Coal Price Forecasts (Real Prices)

	1982 $/MMBtu			
Year [1]	NEPP 6/81 Base case [2]	NEPP 6/81 Low case [3]	AGA Spring 1982 [4]	AGA Fall 1983 [5]
1980	1.30	1.30	1.38	
1981				
1982				1.29
1983				1.34
1984				
1985	1.50	1.41	1.42	1.35
1986	1.51	1.42	1.44	1.37
1987	1.53	1.43	1.45	1.38
1988	1.54	1.43	1.47	1.40
1989	1.56	1.44	1.48	1.41
1990	1.57	1.45	1.50	1.43

Notes:

[2]: U.S. Department of Energy, Office of Policy, Planning, and Analysis. Energy Projections to the Year 2000. July 1981. Table 3-1. Figures are for Midrange average domestic minemouth cost. 1986-89 data have been interpolated assuming a constant rate of escalation.

[3]: U.S. Department of Energy, Office of Policy, Planning, and Analysis. Energy Projections to the Year 2000. July 1981. Table 3-1. Figures are for Low value of Range for average domestic minemouth cost. 1986-89 data have been interpolated assuming a constant rate of escalation.

[4]: American Gas Association. TERA (Total Energy Resource Analysis Model) Analysis 82-1, Table 10. July 13, 1982. Figures are average price across all coal types at minemouth. 1986-89 data have been interpolated assuming a constant rate of escalation.

[5]: American Gas Association. TERA Analysis 82-3, Table 10. November 16, 1983. Figures are average price across all coal types at minemouth. 1986-89 data have been interpolated assuming a constant rate of escalation.

Table 3.3.1
Commonwealth Electric Company:
Projected Avoided Cost of Energy (1983)

Year	Average Avoided Cost of Energy [1] cents/KWh
1985 [2]	5.3
1986	5.9
1987	6.3
1988	6.9
1989	7.9
1990	8.9
1991	10.0
1992	11.8
1993	13.5
1994	15.4
1995	13.8
1996	15.8
1997	17.0
1998	20.1
1999	22.4
2000	25.5
2001	28.9
2002	32.5

Notes:
[1]: January 28, 1983 response to Question 2 of an information request regarding the contract between Corporation Investments, Inc. and Commonwealth Electric Co. dated January 10, 1983. Supporting fuel price forecasts were from Data Resources, Inc.
[2]: 11 months ending December 31, 1985.

Table 3.4.1
Validation of Regression Equation

	$/MMBtu		cents/kWh	
Year [1]	NEPCo's Actual Oil Prices [2]	NEPCo's Actual Coal Prices [3]	Predicted Incremental Energy Costs [4]	Actual Incremental Energy Costs [5]
1985	3.38	1.98	3.68	4.69
1986	2.25	1.80	2.62	3.34
1987	2.51	1.60	2.80	2.98
1988	1.92	1.59	2.21	3.16
1989	2.39	1.57	2.57	3.04
1990	2.93	1.71	3.04	3.32

Notes:

[2]: From NEPCo's FERC filings. Figures represent cost per barrel divided by the given heat content, and are a weighted average of Salem Harbor and Brayton Point plants.

[3]: From NEPCo's FERC filings. Figures represent cost per ton of coal burned divided by the given heat content, and are a weighted average of Salem Harbor and Brayton Point plants.

[4]: ((8950*oil price) + (2776*coal price))/10000 - 0.054*time factor
The time factors for 1985 to 1990 are in order: -2,-2,-2,-1,0,1.

[5]: See Table 2.4.1, column [6].

Table 3.4.2
NEPCo Incremental Costs Expected Under Various Fuel Price Forecasts
(Page 1 of 2)

	cents/KWh					
Forecast	1985	1986	1987	1988	1989	1990
EIA 1980 **	8.0	10.9	10.4	10.8	11.8	13.1
EIA 1981 **	6.6	9.3	9.2	10.1	11.5	13.2
EIA 1982 *	4.1	5.8	6.1	6.6	7.3	8.0
EIA 1983 *	4.1	5.0	4.9	5.4	6.2	7.2
DRI '80/81	9.0	12.6	12.2	13.1	14.7	16.6
DRI 1982 **	5.8	8.1	8.0	8.5	9.6	10.9
Wharton 1980	7.1	9.3	8.8	9.1	9.8	10.8
Wharton 1981	7.2	9.8	9.3	9.8	10.7	11.8
Wharton 1982	5.6	7.7	7.3	7.6	8.1	8.8
Wharton 1983	4.4	5.9	5.7	5.8	6.1	6.5
NEPOOL 1982	8.1	8.9	9.9	10.9	12.1	13.3
NEEPOL 1983	5.6	6.1	6.5	7.0	7.5	8.1

Notes:
These incremental cost expectations are based on the following formula which was derived in the text:
Incremental Cost = (Forecast coal price)*(Coal coefficient) + (Forecast oil price)*(Oil coefficient)/10000 – (Time factor)*(.054)
The numerical inputs to each of the incremental cost calculations are found on page 2 of this table. Forecasted prices for each year have been adjusted to reflect the actual ratio of NEPCo #6 oil or coal prices to actual national prices for crude oil or coal, respectively. The adjustment for 1990 was based on 1989 data. Note that the type of adjustment coefficient for each forecast is specifiesd to the right of the forecast. Each year's coefficients and time trend factor are at the bottom of page 2.

* This coal price forecast only predicted 1985 and 1990 prices. Calculations for the intervening years assumed a constant rate of escalation during that period.
** These oil and coal price forecasts only predicted 1985 and 1990 prices. Calculations for the intervening years assumed a constant rate of escalation during that period.

Sources:
EIA 1980–1983:
Energy Information Administration, from Annual Energy Outlook for the years indicated. Oil forecasts are based on world oil price and assume a heat content of 6.2 MMBtu/bbl. Coal foecast are for price at minemouth, and reflect actual heat content as reported for electric utilities in Annual Energy Review 1989, Table A5.
Wharton 1980–83
Wharton Econometric Forecasting Associates. Wharton Annual Forecasting Model, Energy Price Forecasts, 1980–83, respectively. Prices are for imported crude or domestic coal.
DRI 1980/81
Data Resources, Inc. Energy Review. Outlook of the United States Energy Sector, Winter 1980/81. EIA reported actual prices for CIF coal and >1% sulfur #6 oil were escalated according to DRI's forecasted rates of change.
DRI 1982
Data Resources, Inc. Energy Review. Outlook of the United States Energy Sector, Spring 1982. Prices are for residual oil–industrial or contract (delivered) coal.
NEPOOL 1982
NEPOOL Planning Committe and Generation Task Force. Summary of GTF Long Range Study Assumptions. March 1982. Exhibits 4 and 12. Prices are for 1.5–2.7% sulfur oil or 1.05–2.24% sulfur coal, and include transportation to plant. Heat content oil and coal are assumed to be 6.2 MMBtu/bbl and 26 MMBtu/ton respectively.
NEPOOL 1983
NEPOOL Planning Committe and Generation Task Force. Summary of GTF Long Range Study Assumptions. November 1983. Exhibits 4 and 12 (1/83). Prices are for 1.5–2.7% sulfur oil or 1.05–2.24% sulfur coal, and include transportation to plant. Heat content oil and coal are assumed to be 6.2 MMBtu/bbl and 26 MMBtu/ton respectively.

Table 3.4.2
NEPCo Incremental Costs Expected Under Various Fuel Price Forecasts
(Page 2 of 2)

	Current $/MMBtu						Price Coef– ficient
	1985	1986	1987	1988	1989	1990	
Oil Price Forecast							
EIA 1980 **	9.84	10.82	11.90	13.08	14.38	15.81	crude
EIA 1981 **	7.90	9.11	10.51	12.12	13.98	16.13	crude
EIA 1982 *	4.68	5.48	6.77	7.74	8.71	9.52	crude
EIA 1983 *	4.68	4.68	5.32	6.29	7.42	8.55	crude
DRI '80/81	11.50	12.90	14.50	16.30	18.30	20.50	crude
DRI 1982 **	7.10	8.03	9.07	10.25	11.59	13.10	crude
Wharton 1980	8.67	9.10	9.92	10.81	11.79	12.85	crude
Wharton 1981	8.84	9.72	10.69	11.76	12.94	14.23	crude
Wharton 1982	6.85	7.66	8.39	9.11	9.84	10.62	crude
Wharton 1983	5.13	5.69	6.32	6.83	7.30	7.74	crude
NEPOOL 1982	7.91	8.78	9.74	10.82	12.01	13.33	none
NEPOOL 1983	5.28	5.72	6.18	6.69	7.24	7.83	none
Coal Price Forecast							
EIA 1980 **	2.30	2.49	2.70	2.92	3.16	3.42	FOB
EIA 1981 **	2.20	2.37	2.55	2.74	2.95	3.18	FOB
EIA 1982 *	1.68	1.80	1.94	2.08	2.23	2.40	FOB
EIA 1983 *	1.54	1.64	1.75	1.87	1.99	2.12	FOB
DRI '80/81	2.70	3.00	3.30	3.70	4.10	4.50	CIF
DRI 1982 **	2.40	2.66	2.94	3.26	3.61	4.00	CIF
Wharton 1980	2.18	2.33	2.50	2.72	2.93	3.15	FOB
Wharton 1981	2.07	2.24	2.42	2.65	2.89	3.13	FOB
Wharton 1982	1.60	1.71	1.83	2.00	2.14	2.29	FOB
Wharton 1983	1.50	1.59	1.68	1.79	1.90	2.00	FOB
NEPOOL 1982	3.22	3.54	3.90	4.29	4.72	5.19	none
NEPOOL 1983	2.8	3.03	3.28	3.56	3.85	4.17	none
Price Adjustment and Time Factors							
Oil – Crude	0.777	0.996	0.860	0.817	0.821	0.832	
Coal – FOB	1.650	1.607	1.468	1.514	1.440	1.440	
Coal – CIF	1.200	1.139	1.060	1.082	1.090	1.090	
Time Factor	–2	–2	–2	–1	0	1	

Table 3.5.1
Residual Oil Forecast Comparisons

	Current $/MMBtu				
	Old Forecasts		New Forecasts		
Year	DRI 1980/81	NEPOOL 1982	DRI 1990	NEPOOL 1989	NEPCo 1989
	[1]	[2]	[3]	[4]	[5]
1990	17.00	14.79	2.26	2.67	2.39
1991	18.67	16.12	2.67	2.82	2.50
1992	20.50	17.58	2.84	3.02	2.66
1993	22.50	19.16	3.04	3.23	2.84
1994	24.71	20.88	3.25	3.47	3.02
1995	27.13	22.76	3.50	3.74	3.22
1996	28.98	24.81	3.79	4.14	3.40
1997	30.95	27.04	4.16	4.58	3.59
1998	33.05	29.48	4.58	5.07	3.79
1999	35.30	32.13	5.10	5.61	4.00
2000	37.70	35.02	5.66	6.20	4.22
2001			6.30	6.82	4.41
2002			6.97	7.51	4.61
2003			7.68	8.26	4.82
2004			8.37	9.08	5.03
2005			9.07	9.99	5.26

Notes:

[1]: Data Resources, Inc. Energy Review. Outlook of the United States Energy Sector, Winter 1980/81. Figures are based on an EIA reported actual price for #6 oil (greater than 1% sulfur) and then escalated according to DRI's forecasted rates of change.

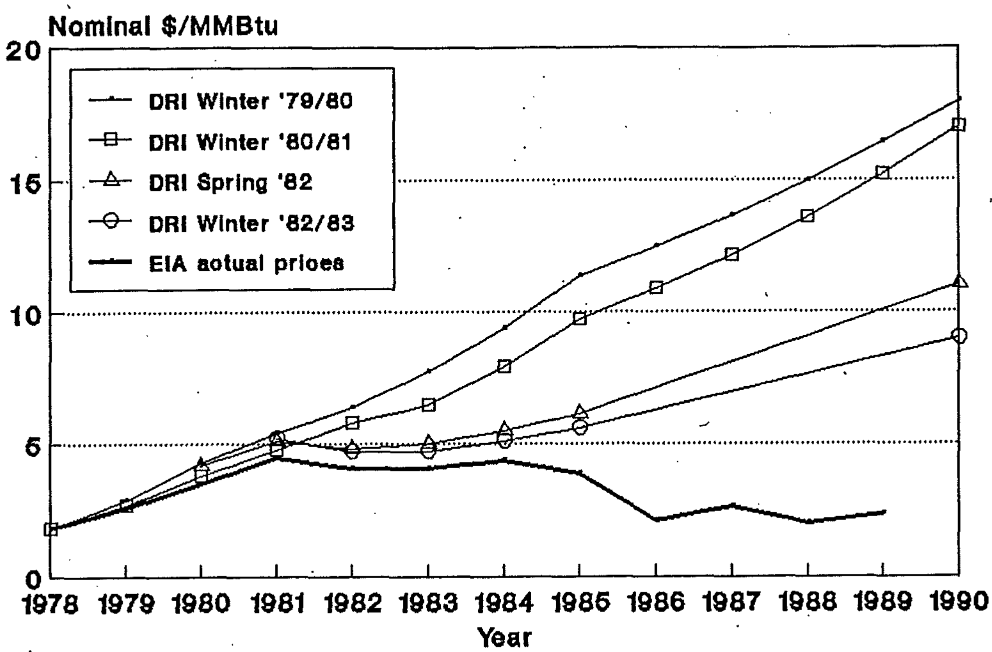
[2]: NEPOOL Planning Committee and Generation Task Force. Summary of GTF Long-Range Study Assumptions, March, 1982. Exhibits 4 and 12. Figures are for residual oil containing 1.5-2.7% sulfur.

[3]: Data Resources, Inc./McGraw-Hill Energy Services. Boston Edison Company Energy Price Forecast, July 1990. Table A-&. Figure are for 2.2% residual oil.

[4]: NEPOOL Planning Committee and Generation Task Force. Summary of Generation Task Force Long-Range Study Assumptions, December 1989. Pages 16 and 36 (Exhibits 4 and 19). Figures are for 2.2% sulfur residual oil.

[5]: New Engleand Energy Incorporated. Review of Energy Market Conditions and Update of Fuel Price Projections, December, 1989. Page 63. Figures are for 2.2% sulfur residual.

Figure 3.2.1
DRI Residual Oil Price Forecasts



Notes:

DRI Winter '79/80

Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, 1979/80.
1978 price was taken from EIA's reported actuals for #6 residual oil (having greater than 1% sulfur) to end users (excluding taxes), and then escalated according to DRI's forecasted rates of change.

DRI Winter '80/81

Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, 1980/1.
1978 price was taken from EIA's reported actuals for #6 residual oil (having greater than 1% sulfur) to end users (excluding taxes), and then escalated according to DRI's forecasted rates of change.

DRI Spring '82

Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, Spring 1982.
Prices are for "residual oil industrial."

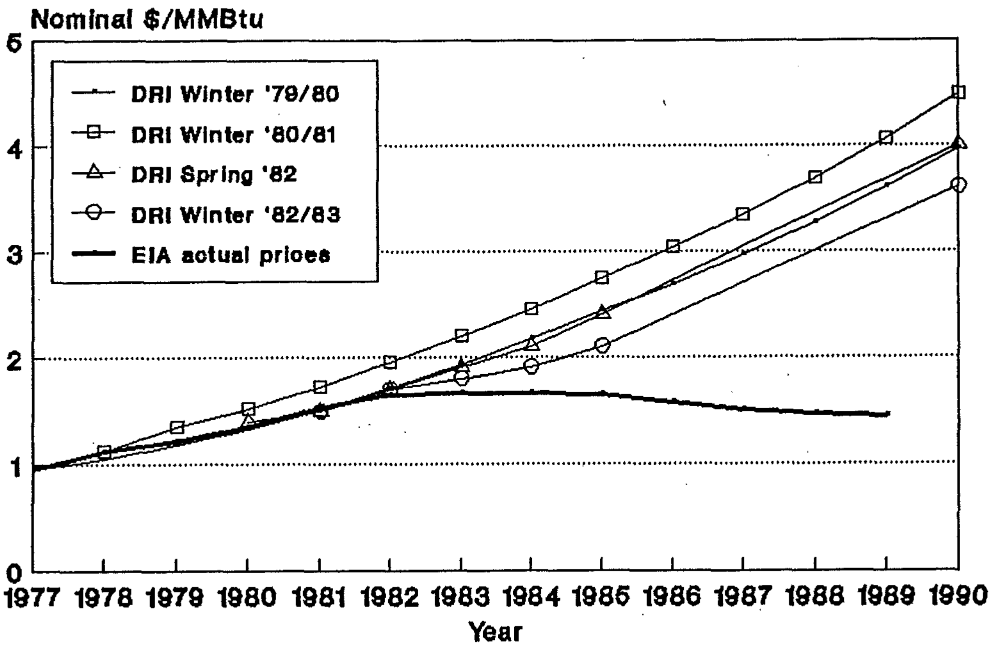
DRI Winter '82/83

Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, Winter 1982/3.
Prices are for "residual oil industrial."

EIA actual prices

D.O.E. Energy Information Administration. Annual Energy Review 1989, Table 69. Data is for #6 oil having >1% sulfur, and represent price to end users, excluding taxes. Heat content is assumed to be 6.3 MMBtu/bbl.

Figure 3.2.2
DRI Delivered Coal Price Forecasts



Notes:

DRI Winter '79/80

Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, 1979/80.
Base year price was taken from Annual Energy Review 1989 CIF coal prices (See Table 2.4.3 [3]) and then adjusted according to DRI's rate of change forecasts.

DRI Winter '80/81

Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, 1980/1.
Base year price was taken from Annual Energy Review 1989 CIF coal prices (See Table 2.4.3 [3]) and then adjusted according to DRI's rate of change forecasts.

DRI Spring '82

Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, Spring 1982.
Prices are for delivered/contract coal.

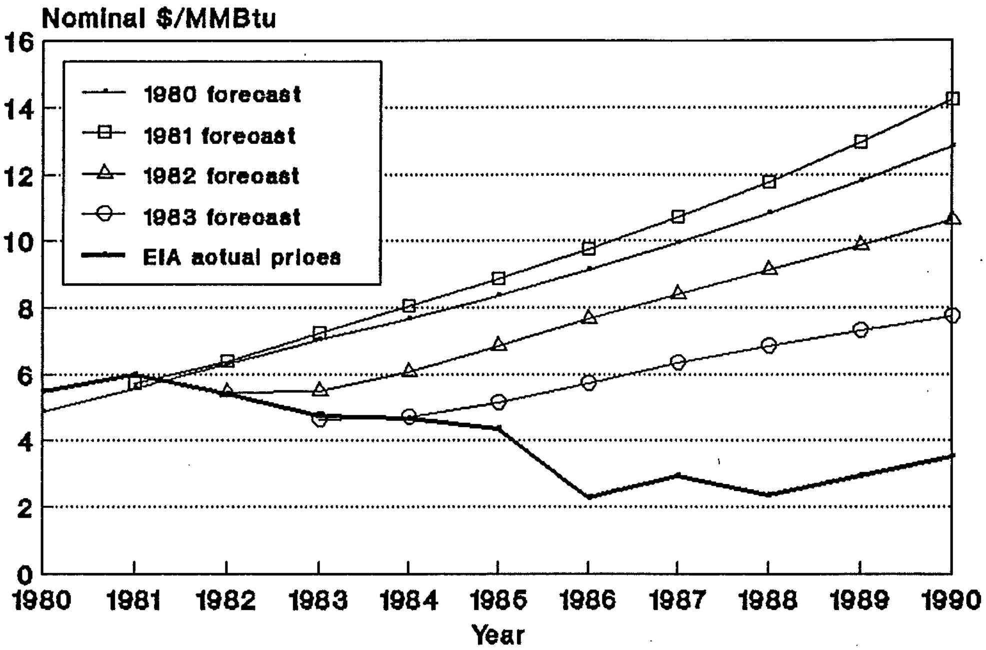
DRI Winter '82/83

Data Resources, Inc. Energy Review, Outlook of the United States Energy Sector, Winter 1982/3.
Prices are for delivered/contract coal.

EIA actual prices

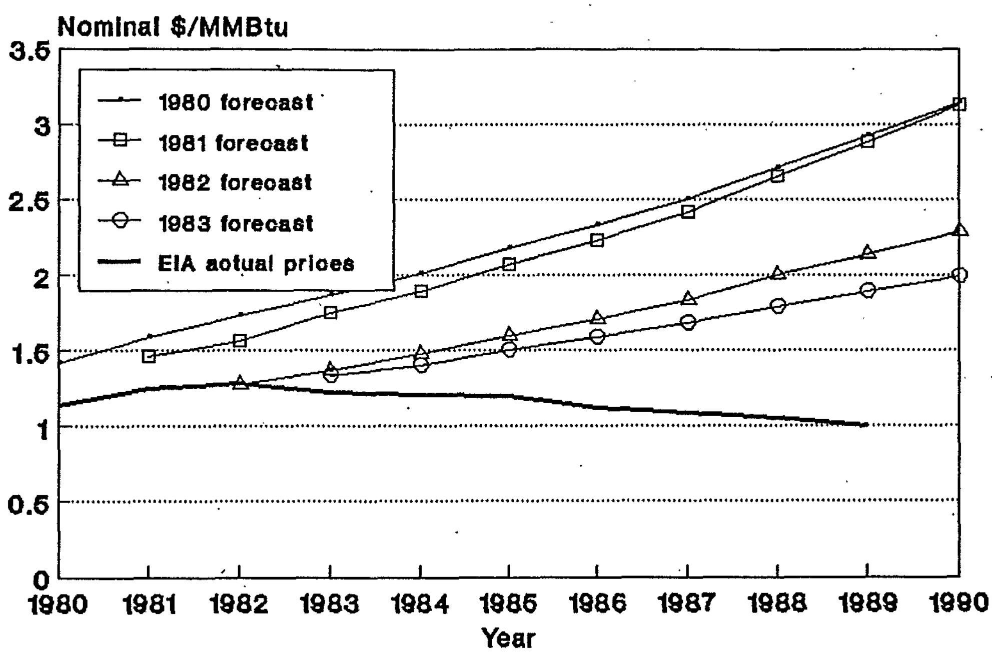
D.O.E. Energy Information Administration. Annual Energy Review 1989, Table 86. Prices include cost, insurance, and freight (CIF) for electric utility plants.

Figure 3.2.3
Wharton Imported Crude Price Forecasts



Notes:
1980, 1981, 1982, and 1983 forecasts
Wharton Econometric Forecasting Associates. Wharton Annual Forecasting Model, Energy Price Forecasts, 1980, 1981, 1982, 1983, respectively. Forecasts are for imported oil.
EIA actual prices
D.O.E. Energy Information Administration. Annual Energy Review 1989, Table 68. 1990 figure provided by phone. Prices are refiner acquisition cost of imported crude, and heat content of 6.2 MMBtu/bbl is assumed.

Figure 3.2.4
Wharton Coal Price Forecasts



Notes:

1980, 1981, 1982, and 1983 forecasts

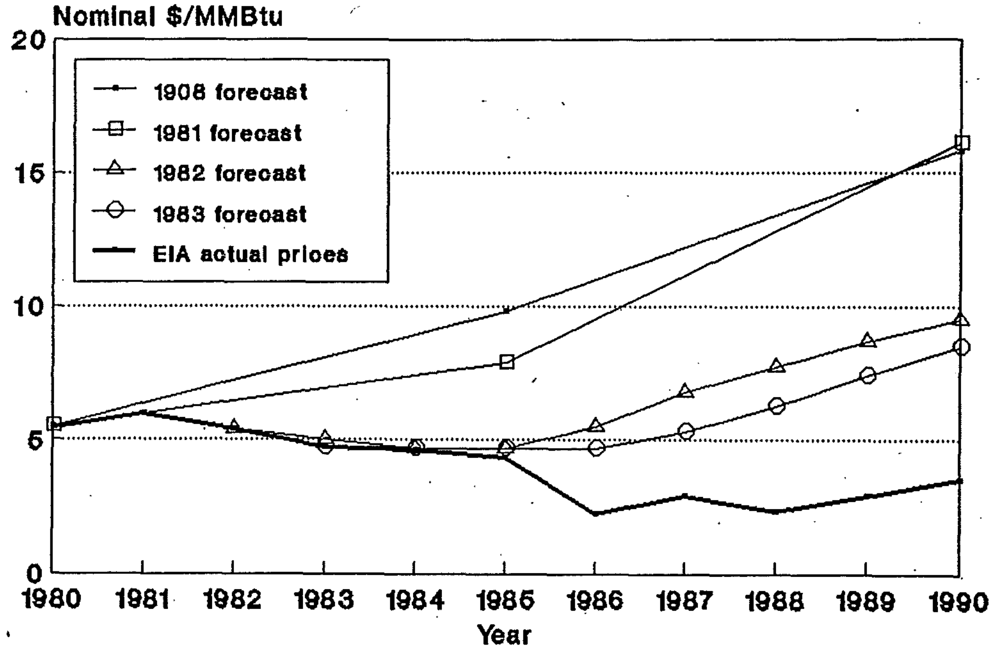
Wharton Econometric Forecasting Associates. Wharton Annual Forecasting Model, Energy Price Forecasts, 1980, 1981, 1982, 1983, respectively. Forecasts are for domestic coal.

EIA actual prices

D.O.E. Energy Information Administration. Annual Energy Review 1989, Table 86. Prices are free on board (FOB) mines and heat content assumptions are from AER 1989, Table A5 for electric utilities.

Figure 3.2.5

EIA Base Case Crude Oil Price Forecasts



Notes:

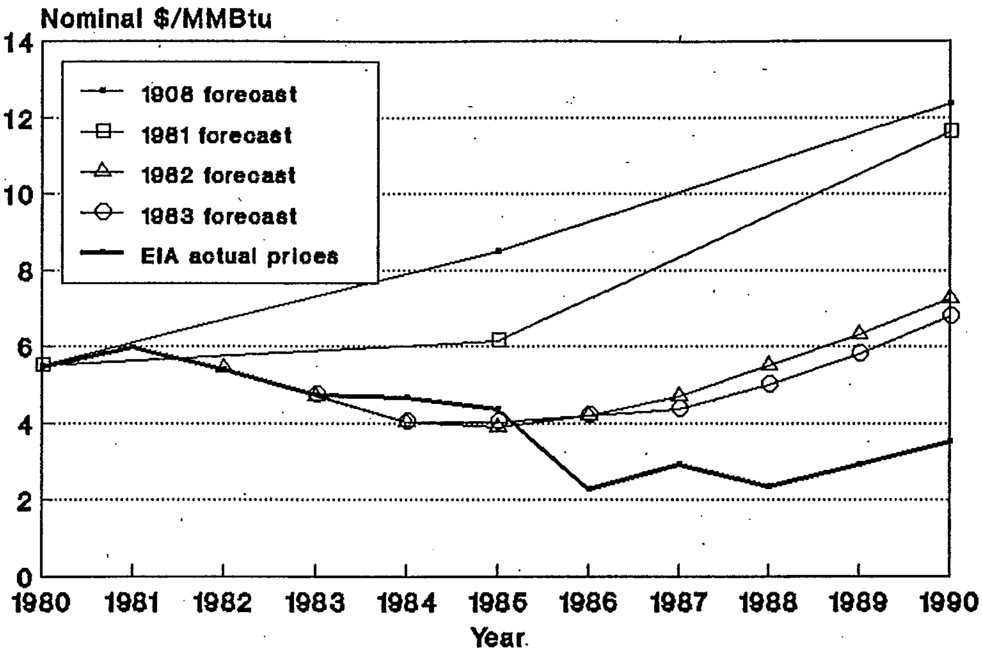
1980, 1981, 1982, and 1983 forecasts

D.O.E Energy Information Administration, excerpted from Annual Energy Outlook 1980, 1981, 1982, 1nd 1983, respectively. Figures are for World Oil Price, and heat content of 6.2 MMBtu/bbl is assumed.

EIA actual prices

D.O.E. Energy Information Administration. Annual Energy Review 1989, Table 68. 1990 figure provided by phone. Prices are refiner acquisition cost of imported crude, and heat content of 6.2 MMBtu/bbl is assumed.

Figure 3.2.6
EIA Low Crude Oil Price Forecasts



Notes:
1980, 1981, 1982, and 1983 forecasts

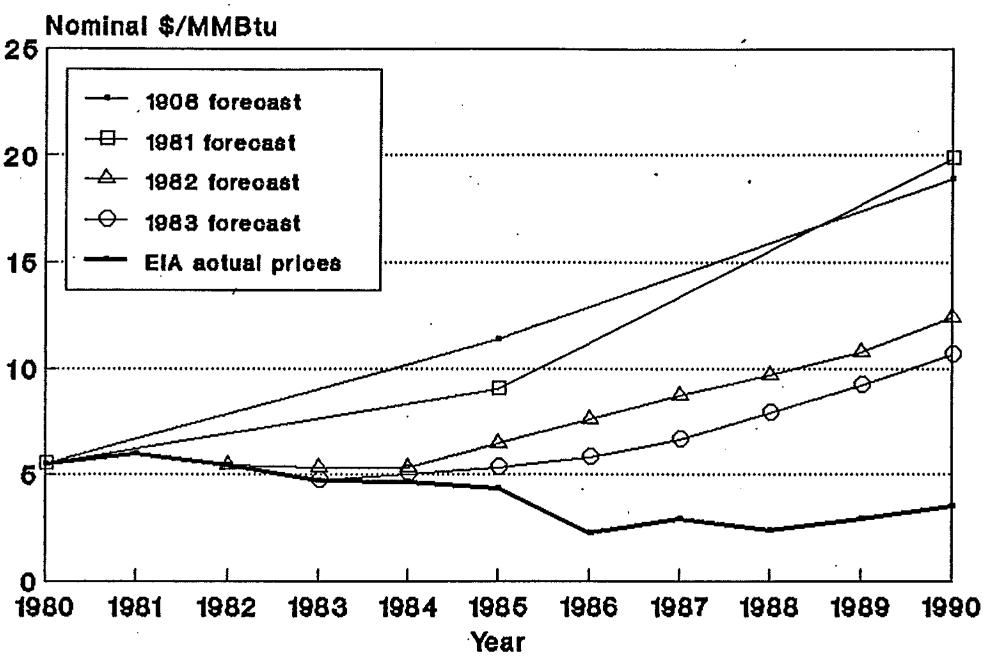
D.O.E Energy Information Administration, excerpted from Annual Energy Outlook 1980, 1981, 1982, 1nd 1983, respectively. Figures are for World Oil Price, and heat content of 6.2 MMBtu/bbl is assumed.

EIA actual prices

D.O.E. Energy Information Administration. Annual Energy Review 1989, Table 68. 1990 figure provided by phone. Prices are refiner acquisition cost of imported crude, and heat content of 6.2 MMBtu/bbl is assumed.

Figure 3.2.7

EIA High Crude Oil Price Forecasts



Notes:

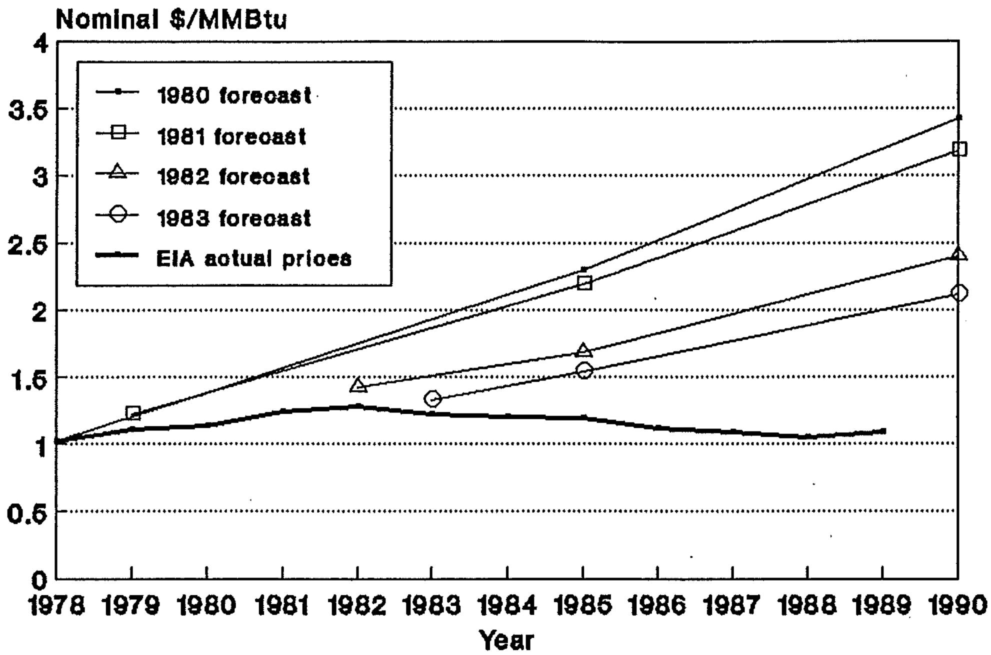
1980, 1981, 1982, and 1983 forecasts

D.O.E Energy Information Administration, excerpted from Annual Energy Outlook 1980, 1981, 1982, 1nd 1983, respectively. Figures are for World Oil Price, and heat content of 6.2 MMBtu/bbl is assumed.

EIA actual prices

D.O.E. Energy Information Administration. Annual Energy Review 1989, Table 68. 1990 figure provided by phone. Prices are refiner acquisition cost of imported crude, and heat content of 6.2 MMBtu/bbl is assumed.

Figure 3.2.8
EIA Base Case Coal Price Forecasts



Notes:
1980, 1981, 1982, and 1983 forecasts

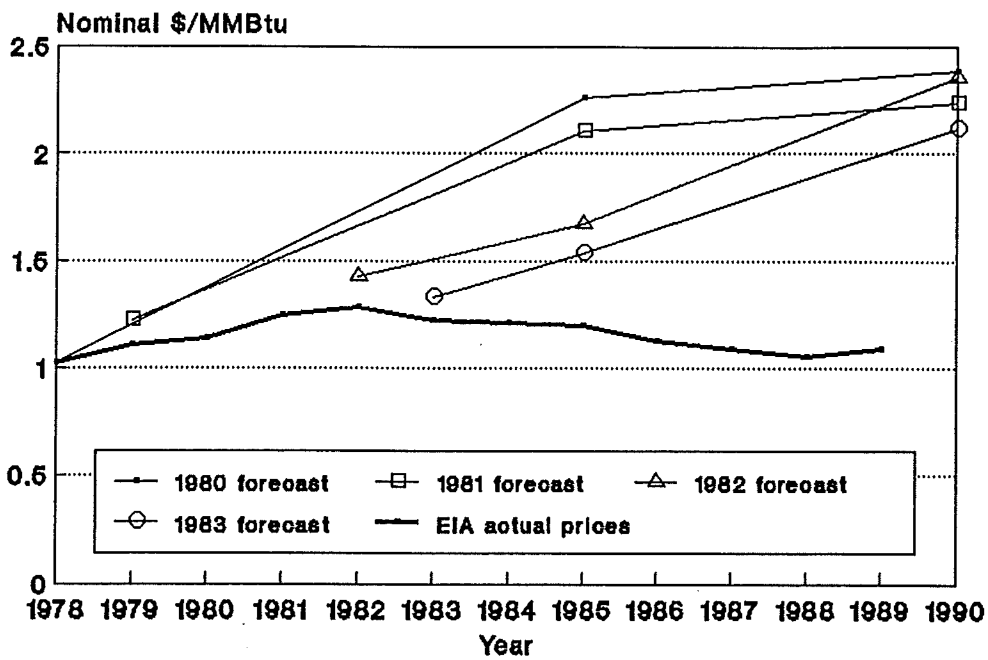
Eugene Reiser of Energy Information Administration, from Annual Energy Outlook 1980,1981,1982, and 1983, respectively.

Forecasts are as under a mid-range oil price scenario. Price is at minemouth and reflects actual heat content as reported for electric utilities in Annual Energy Review 1989, Table A5. The 1989 figure was used for 1990 calculations.

EIA actual prices

D.O.E. Energy Information Administration. Annual Energy Review 1989, Table 86. Prices are free on board (FOB) mines, and heat content is from Table A5 for Electric Utilities.

Figure 3.2.9
EIA Low Case Coal Price Forecasts



Notes:

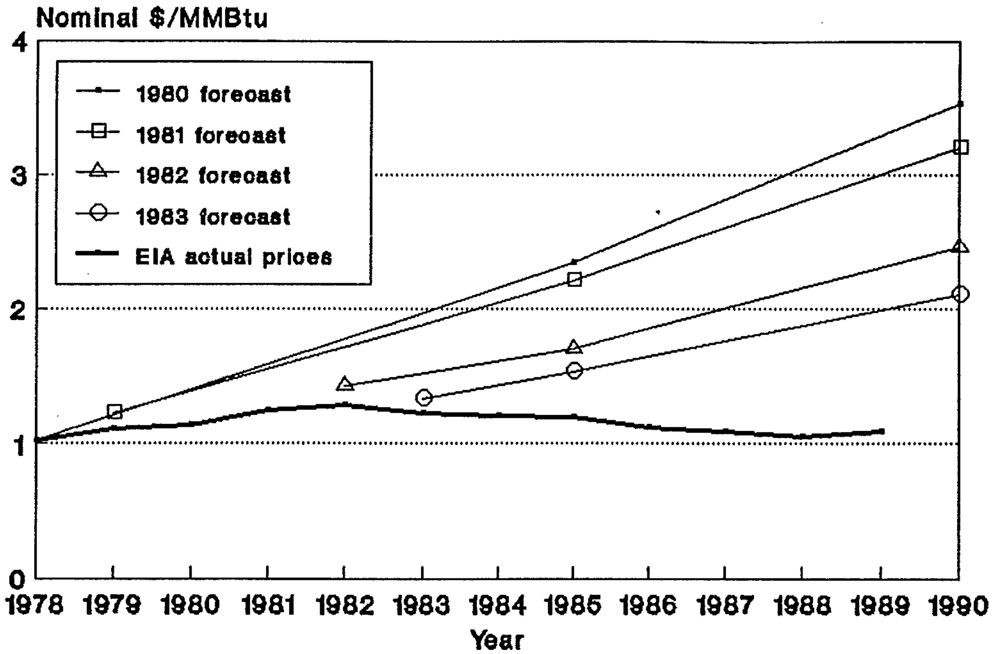
1980, 1981, 1982, and 1983 forecasts

Eugene Reiser of Energy Information Administration, from Annual Energy Outlook 1980,1981,1982, and 1983, respectively.
Forecasts are as under a low oil price scenario. Price is at minemouth and reflects actual heat content as reported for electric utilities in Annual Energy Review 1989, Table A5. The 1989 figure was used for 1990 calculations.

EIA actual prices

D.O.E. Energy Information Administration. Annual Energy Review 1989, Table 86. Prices are free on board (FOB) mines, and heat content is from Table A5 for Electric Utilities.

Figure 3.2.10
EIA High Case Coal Price Forecasts



Notes:

1980, 1981, 1982, and 1983 forecasts

Eugene Reiser of Energy Information Administration, from Annual Energy Outlook 1980,1981,1982, and 1983, respectively.
Forecasts are as under a high oil price scenario. Price is at minemouth and reflects actual heat content as reported for electric utilities in Annual Energy Review 1989, Table A5. The 1989 figure was used for 1990 calculations.

EIA actual prices

D.O.E. Energy Information Administration. Annual Energy Review 1989, Table 86. Prices are free on board (FOB) mines, and heat content is from Table A5 for Electric Utilities.

Figure 3.2.11

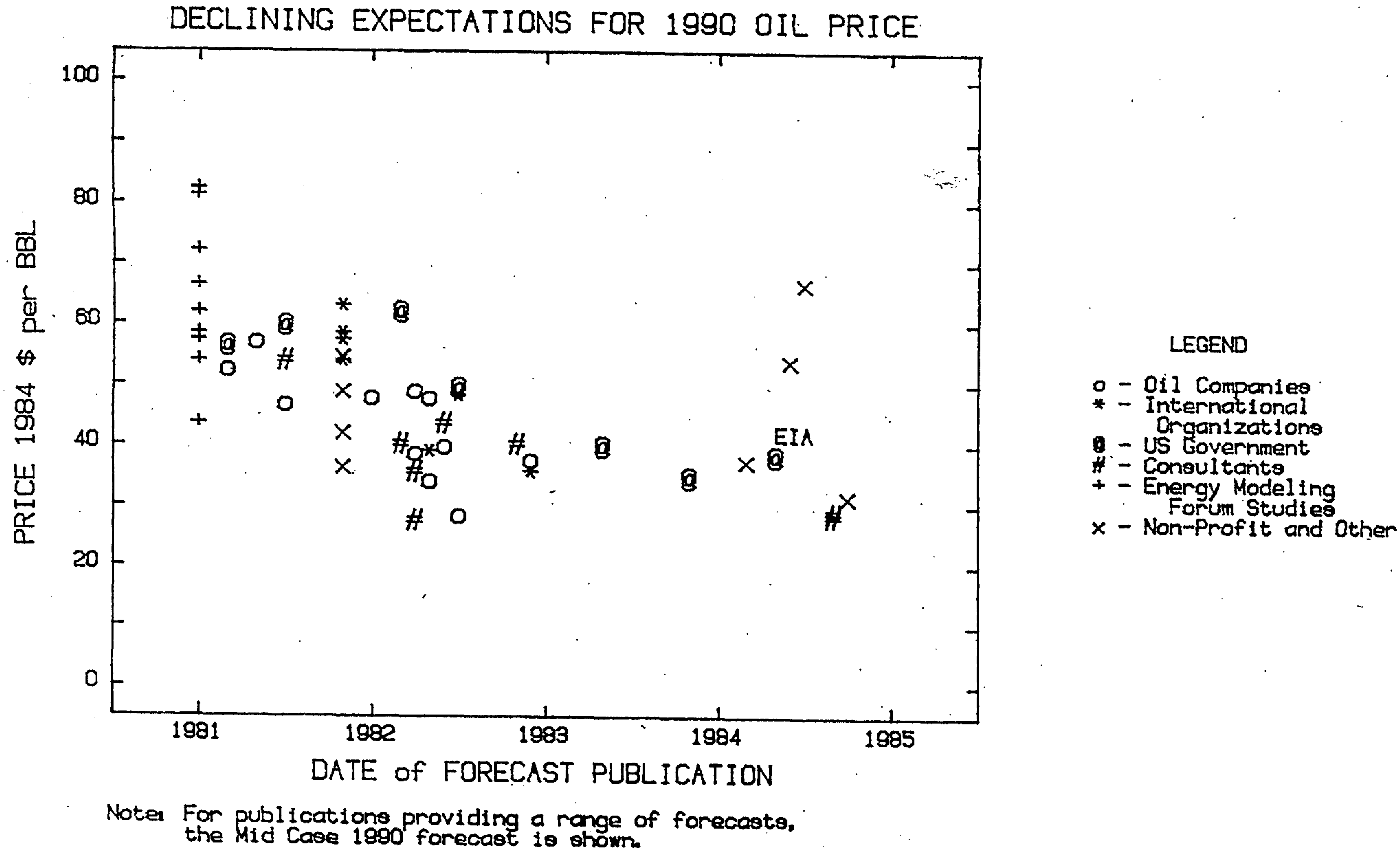
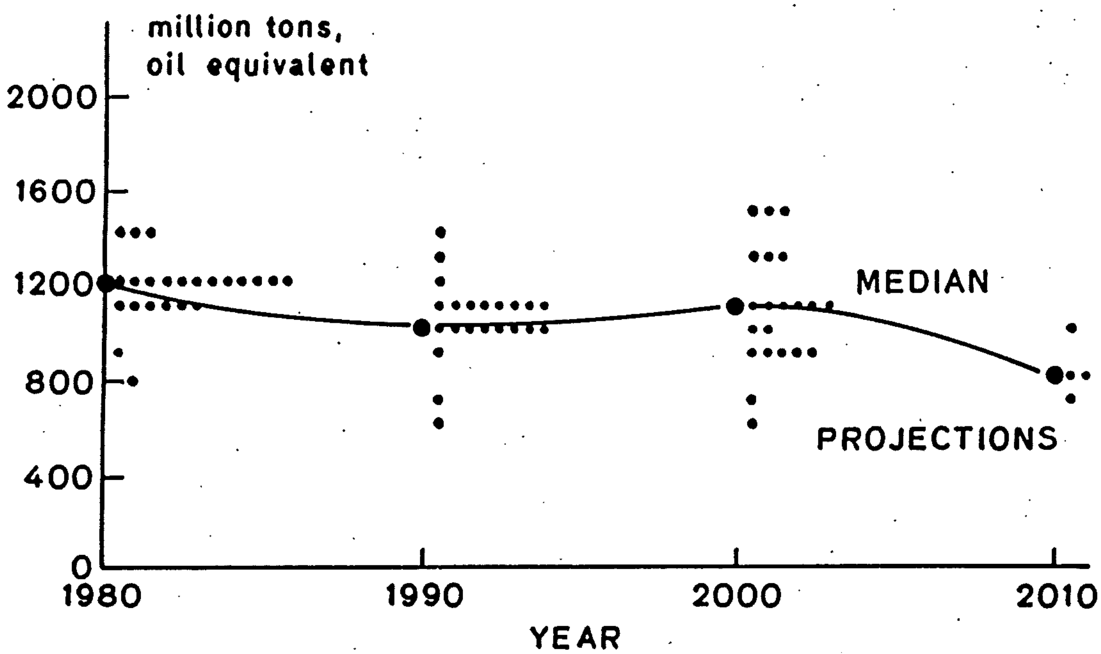


Figure 1. Uncertainty dominates oil price forecasts.

Figure 3.2.12

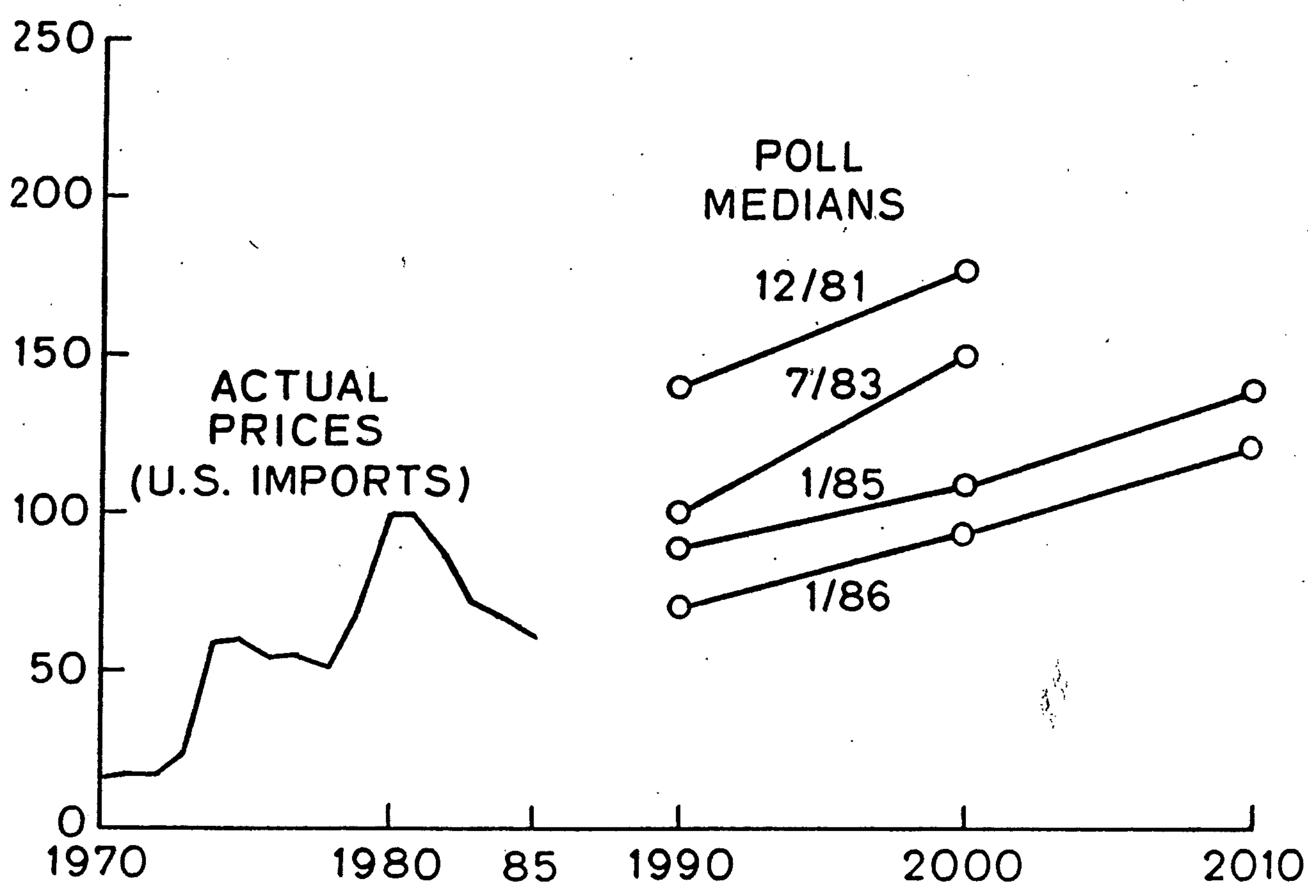


Respondent	1980	Respondent	1990	Respondent	2000	Respondent	2010
sohn	1442	stohs	1395	aohn	1499	opecl	1050
stols	1360	sohn	1253	oriea	1475	iiasa	842
stohs	1360	bph	1190	ieahd	1454	cerg	805
opecl	1210	ieahd	1140	stohs	1310	DOE	725
DOE	1185	gulfb	1125	gulfb	1285		
ipe	1181	respa	1112	bph	1267		
cerg	1181	wbk	1109	opecl	1145		
ieald	1180	opecl	1107	ind	1145		
ieahd	1180	eni	1094	wbk	1122		
iea83	1180	stols	1090	iea83	1113		
bpl	1171	iea83	1068	con	1087		
bph	1171	DOE	1025	ipe	1056		
gulfb	1170	cerg	1020	cerg	993		
wbk	1155	ipe	1015	3rt	980		
ind	1155	respc	1010	DOE	935		
eni	1148	ind	1010	respa	896		
con	1144	con	995	stols	875		
respc	1135	ieald	975	ieald	872		
respb	1112	bpl	974	bpl	872		
respa	1112	3rt	940	iiasa	726		
3rt	1085	iiasa	712	respb	613		
oriea	876	respb	608				
iiasa	797						

Figure 2. OECD oil imports (mtoe).

Figure 3.2.13

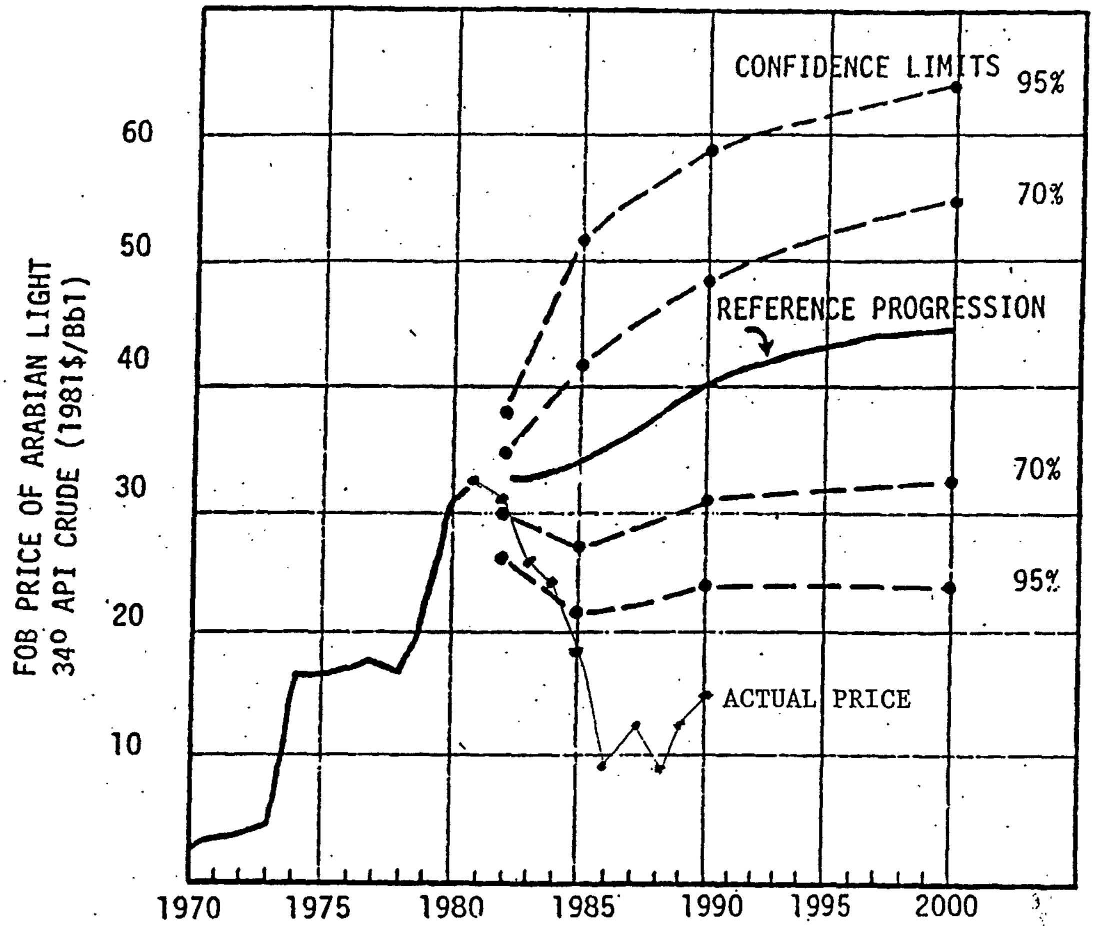
International Energy Workshop: Oil Price Projections



. **Comparison of four successive IEW polls and actual prices.**

FIGURE 3.2.14

ARTHUR D. LITTLE DELPHI SURVEY OF CRUDE OIL PRICES - AUGUST 1981[1]
VERSUS ACTUAL PRICES



August 1981 Survey	1981 ACTUAL	1985	1990	2000
Reference Progression	32.0	35.5	40.8	45.2
Actual Prices[2]	32.5	18.7	14.9	

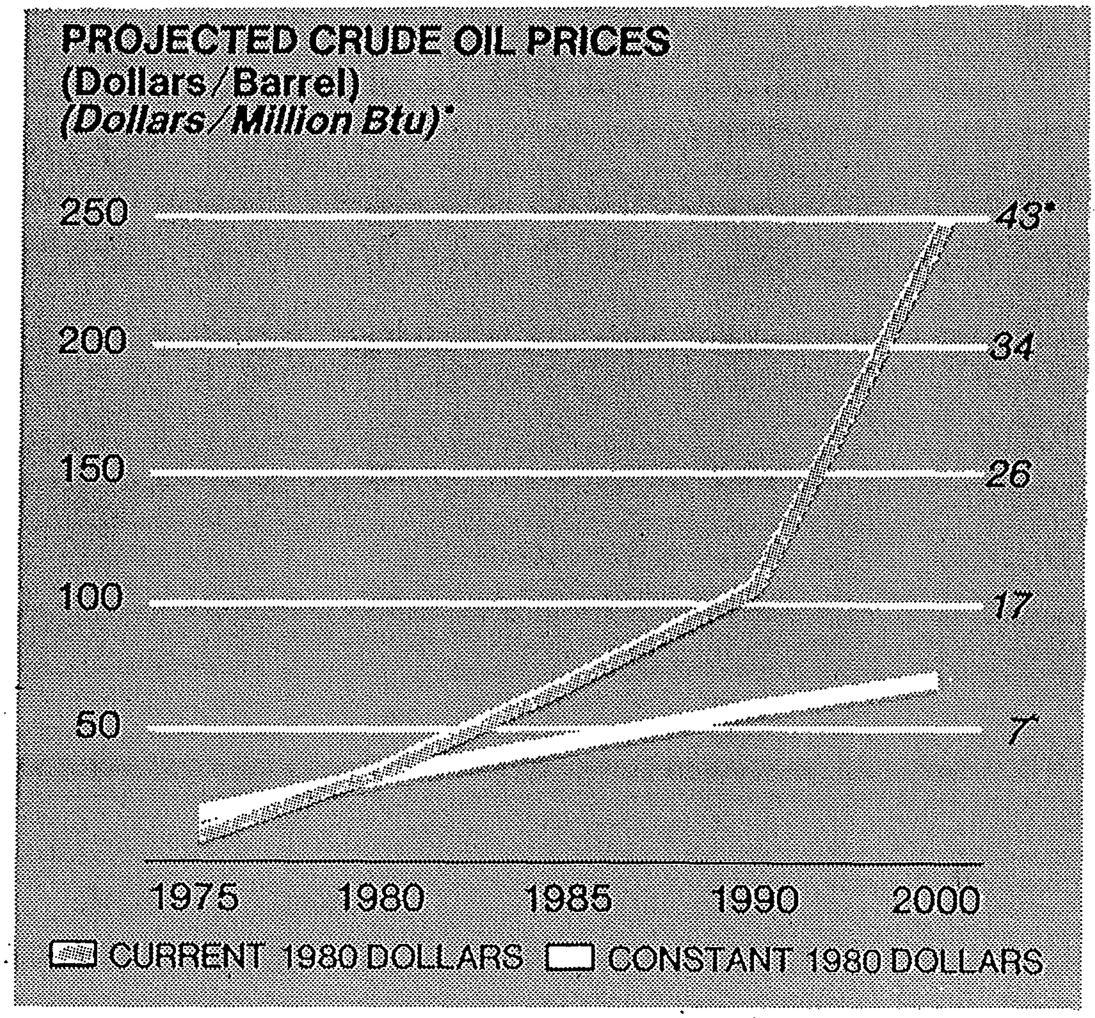
Notes

1 Reproduced from A.D. Little. Prepared Direct Testimony of Mary M. Menino in DPU 1120, July 1, 1982 - Amended as noted below

2 Actual Prices are FOB cost of Saudi Arabian Crude as provided by Department of Energy, Energy Information Administration, Charles River, contact. Added April 1991 by Resource Insight, Inc.

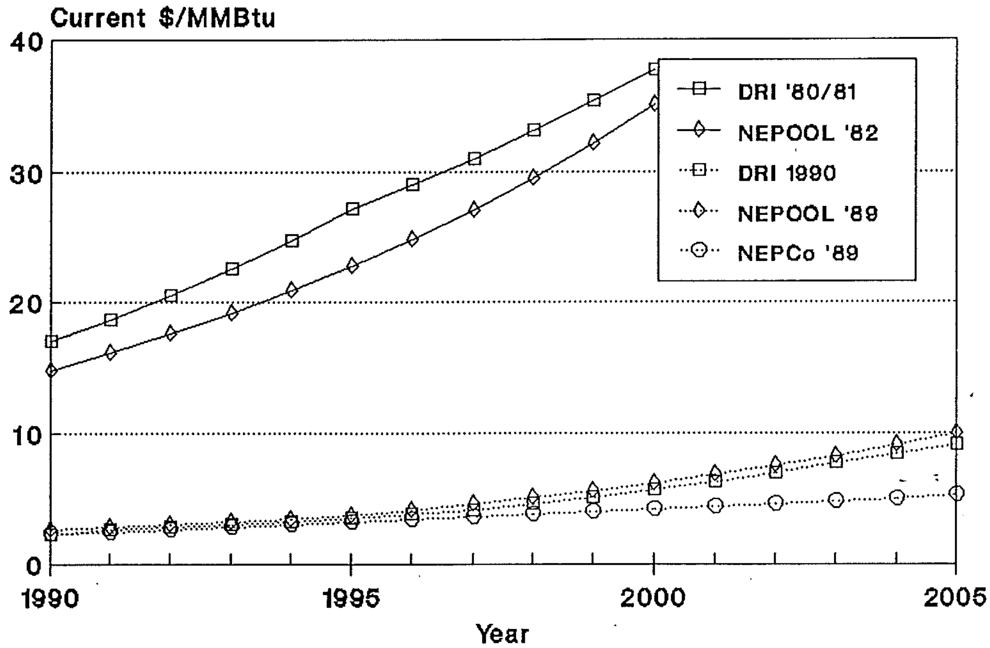
Figure 3.2.15

California Energy Commission
1981 Crude Oil Price Forecast



Reproduced from California Energy Commission 1981 Biennial Report: Energy Tomorrow: Challenges and Opportunities for California. Page 33.

Figure 3.5.1
Residual Oil Price Forecasts



Notes:

DRI '80/81

Data Resources, Inc. Energy Review. Outlook of the United States Energy Sector, Winter 1980/81. Figures are based on an EIA reported actual price for #6 oil (greater than 1% sulfur) and then escalated according to DRI's forecasted rates of change.

NEPOOL '82

NEPOOL Planning Committee and Generation Task Force. Summary of GTF Long-Range Study Assumptions, March, 1982. Exhibits 4 and 12. Figures are for residual oil containing 1.5-2.7% sulfur.

DRI 1990

Data Resources, Inc./McGraw-Hill Energy Services. Boston Edison Company Energy Price Forecast, July 1990. Table A-&. Figures are for 2.2% sulfur residual oil.

NEPOOL '89

NEPOOL Planning Committee and Generation Task Force. Summary of Generation Task Force Long-Range Study Assumptions, December 1989. Pages 16 and 36 (Exhibits 4 and 19). Figures are for 2.2% sulfur residual oil.

NEPCo '89

New Engleand Energy Incorporated. Review of Energy Market Conditions and Update of Fuel Price Projections, December, 1989. Page 63. Figures are for 2.2% sulfur residual.

Table 4.1
Estimated MRI Losses from Unforeseen Reduction in Fuel Prices

	$/kWh					Costs ($1000)	
Year [1]	Projected Average Incremental Fuel Costs [2]	Actual Fuel Cost [3]	Current Projected Fuel Cost [4]	Fuel Cost Difference [5]	Energy Rate Difference [6]	Annual Loss [7]	MRI Share of Loss [8]
1986	0.072	0.033		0.039	0.035	8251	866
1987	0.079	0.030		0.049	0.044	10589	1112
1988	0.086	0.030		0.056	0.050	11613	1219
1989	0.094	0.029		0.065	0.059	13723	1441
1990	0.102	0.029		0.073	0.066	14853	1560
1991	0.111		0.031	0.080	0.072	16593	1742
1992	0.121		0.032	0.089	0.080	18437	1936
1993	0.132		0.034	0.098	0.088	20281	2129
1994	0.144		0.036	0.108	0.097	22355	2347
1995	0.157		0.037	0.120	0.108	24890	2613
1996	0.171		0.039	0.132	0.119	27425	2880
1997	0.187		0.041	0.146	0.131	30191	3170
1998	0.204		0.043	0.161	0.145	33417	3509
1999	0.222		0.046	0.176	0.158	36413	3823
2000	0.242		0.048	0.194	0.175	40331	4235
2001	0.264		0.050	0.214	0.193	44479	4670
2002	0.287		0.053	0.234	0.211	48628	5106
2003	0.313		0.055	0.258	0.232	53467	5614
2004	0.341		0.058	0.283	0.255	58768	6171
2005	0.372		0.061	0.311	0.280	64530	6776

Notes:

[2]: Weston. Northeast Massachusetts Resource Recovery Project: Consulting Engineers Feasibility Report, Appendix A to Official Statement. (1983)

[3]: Energy rate divided by 90%. From MRI Proposed Findings of Fact (p. 38).

[4]: 1990 fuel cost (from [3]), escalated at 5%.

[5]: 1986-90: [2]-[3]
1991-2005: [2]-[4]

[6]: [5]*0.9

[7]: [6]*[annual energy sales]. MRI reports these as:

1986	235,746 MWh
1987	240,661 MWh
1988	232,259 MWh
1989	232,586 MWh
1990	225,051 MWh

and projects an average of 230,463 MWh in their 5-Year Strategic Plan. This figure has been assumed to carry through 2005.

[8]: [7]*10.5%

ATTACHMENT MRI-PLC-2

FUEL MIX REGRESSIONS FOR LOW, BASE, AND HIGH FUEL PRICE FORECASTS, NEEI 9/87.

TABLE 1: FUEL REGRESSIONS FOR YEARS 1987-1991

CALCULATED VALUE	AVOIDED ENERGY COST 2.2%	OIL	COAL	GAS	TIME	YEAR	PRICE FORECAST
0.0248150	0.02417	2.16	1.58	0	-2	1987	LOW
0.0253200	0.02538	2.24	1.69	0	-1	1988	LOW
0.0257709	0.02617	2.33	1.75	0	0	1989	LOW
0.0262545	0.02628	2.43	1.82	0	1	1990	LOW
0.0269029	0.02683	2.53	1.94	3.26	2	1991	LOW
0.0307232	0.03006	2.82	1.58	0	-2	1987	BASE
0.0293347	0.02967	2.69	1.68	0	-1	1988	BASE
0.0302286	0.03086	2.83	1.75	0	0	1989	BASE
0.0311918	0.03119	2.98	1.82	0	1	1990	BASE
0.0322527	0.03193	3.12	1.94	3.74	2	1991	BASE
0.0320607	0.03172	2.97	1.58	0	-2	1987	HIGH
0.0334401	0.03409	3.15	1.69	0	-1	1988	HIGH
0.0349223	0.03571	3.34	1.81	0	0	1989	HIGH
0.0365402	0.0364	3.54	1.94	0	1	1990	HIGH
0.0383025	0.03763	3.76	2.07	4.37	2	1991	HIGH

Regression Output:

Constant	0
Std Err of Y Est	0.000522
R Squared	0.986757
No. of Observations	15
Degrees of Freedom	12

	OIL	COAL	TIME
X Coefficient(s)	0.008950	0.002776	-0.00054
Std Err of Coef.	0.000353	0.000575	0.000096

TABLE 2: FUEL REGRESSIONS FOR YEARS 1992-1997

CALCULATED VALUE	AVOIDED ENERGY COST	2.2% OIL	COAL	GAS	TIME	YEAR	PRICE FORECAST
0.0309189	0.03162	2.63	2.04	3.18	-3	1992	LOW
0.0335164	0.03419	2.73	2.14	3.30	-2	1993	LOW
0.0349973	0.03678	2.84	2.25	3.31	-1	1994	LOW
0.0364817	0.03708	2.95	2.36	3.32	0	1995	LOW
0.0393024	0.03917	3.07	2.49	3.46	1	1996	LOW
0.0414134	0.04131	3.20	2.61	3.53	2	1997	LOW
0.0436334	0.04353	3.32	2.74	3.61	3	1998	LOW
0.0374625	0.03599	3.28	2.04	3.82	-3	1992	BASE
0.0410319	0.03956	3.45	2.14	4.04	-2	1993	BASE
0.0431217	0.04312	3.62	2.25	4.11	-1	1994	BASE
0.0453480	0.04413	3.80	2.37	4.19	0	1995	BASE
0.0485981	0.0473	4.00	2.49	4.37	1	1996	BASE
0.0516164	0.05063	4.20	2.61	4.53	2	1997	BASE
0.0548736	0.05406	4.42	2.74	4.71	3	1998	BASE
0.0446953	0.04462	3.99	2.22	4.51	-3	1992	HIGH
0.0493439	0.0492	4.23	2.33	4.83	-2	1993	HIGH
0.0523654	0.05402	4.49	2.45	4.99	-1	1994	HIGH
0.0554960	0.05534	4.76	2.57	5.16	0	1995	HIGH
0.0594505	0.05979	5.05	2.70	5.41	1	1996	HIGH
0.0637182	0.06443	5.36	2.84	5.69	2	1997	HIGH
0.0681971	0.0694	5.68	2.98	5.99	3	1998	HIGH

Regression Output:

Constant	0
Std Err of Y Est	0.001014
R Squared	0.991029
No. of Observations	21
Degrees of Freedom	18

	COAL	GAS	TIME
X Coefficient(s)	0.001088	0.010212	0.001259
Std Err of Coef.	0.000635	0.000357	0.000113

TABLE 3: FUEL REGRESSIONS FOR YEARS 1998-2006

CALCULATED VALUE	AVOIDED ENERGY COST	2.2% OIL	COAL	GAS	TIME	YEAR	PRICE FORECAST
0.04540	0.04754	3.46	2.88	3.65	-3	1999	LOW
0.04834	0.04988	3.59	3.02	3.74	-2	2000	LOW
0.05089	0.05231	3.74	3.18	3.79	-1	2001	LOW
0.05431	0.05447	3.89	3.34	3.92	0	2002	LOW
0.05627	0.05680	4.05	3.50	3.91	1	2003	LOW
0.05901	0.05939	4.20	3.68	3.97	2	2004	LOW
0.06188	0.06196	4.37	3.87	4.04	3	2005	LOW
0.06501	0.06462	4.55	4.06	4.13	4	2006	LOW
0.05828	0.05731	4.63	2.88	4.85	-3	1999	BASE
0.06235	0.06071	4.86	3.03	5.05	-2	2000	BASE
0.06598	0.06471	5.11	3.19	5.20	-1	2001	BASE
0.07057	0.06890	5.37	3.33	5.44	0	2002	BASE
0.07377	0.07258	5.64	3.50	5.54	1	2003	BASE
0.07783	0.07659	5.92	3.68	5.73	2	2004	BASE
0.08220	0.08107	6.22	3.87	5.94	3	2005	BASE
0.08669	0.08560	6.53	4.07	6.15	4	2006	BASE
0.07439	0.07419	6.03	3.13	6.27	-3	1999	HIGH
0.07995	0.07938	6.39	3.28	6.60	-2	2000	HIGH
0.08522	0.08530	6.78	3.45	6.90	-1	2001	HIGH
0.09159	0.09158	7.20	3.62	7.30	0	2002	HIGH
0.09660	0.09729	7.63	3.81	7.57	1	2003	HIGH
0.10272	0.10362	8.10	4.00	7.94	2	2004	HIGH
0.10919	0.11065	8.59	4.20	8.34	3	2005	HIGH
0.11624	0.11782	9.11	4.41	8.79	4	2006	HIGH

Regression Output:

Constant	0
Std Err of Y Est	0.001181
R Squared	0.996660
No. of Observations	24
Degrees of Freedom	21

	COAL	GAS	TIME
X Coefficient(s)	0.003688	0.010715	0.001442
Std Err of Coef.	0.000309	0.000187	0.000109

ATTACHMENT MRI-PLC-3

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ohn Hancock Tower, 43rd Floor
00 Clarendon Street
oston, MA 02116

International Energy Workshop: A Summary of the 1983 Poll Responses

Alan S. Manne and Leo Schrattenholzer***

INTRODUCTION

Energy forecasting is a hazardous occupation. Virtually any projection is doomed to be incorrect. Opinions can swing from one extreme to another during a six-month period. Our paper is not intended to provide still another projection, but rather to try to explain why different individuals and organizations arrive at divergent views on the long-term energy outlook—and therefore differ on policy decisions.

This paper is an interim report on the current activities of an informally organized group known as the IEW (International Energy Workshop). The general aim is to compare the most up-to-date, long-term energy projections available throughout the world, and to obtain a better understanding of the reasons for their differences. Participation is open to any individual who is prepared to contribute to the aims of the IEW. Usually, such a contribution consists of summarizing one or more energy scenarios by filling in the poll form shown in Appendix Table A-1. The first workshop meeting was held at Stanford University in December 1981, and the second at IIASA (the International Institute for Applied Systems Analysis, Laxenburg, Austria) in June 1983.

The poll covers only items that are comparable in existing international energy statistics: crude-oil prices, GNP growth, primary energy consumption and production, and electricity generation. Typically, the respondents provide a reference case ("surprise-free") scenario. In a few instances, there are disruption and/or alternative growth cases. No probability estimates are assigned to individual projections.

The Energy Journal, Vol. 5, No. 1

Presented at the International Energy Workshop, IIASA, June 14–16, 1983, in Laxenburg, Austria.

The individual authors are solely responsible for this analysis, but are indebted to Mark Beltramo, Chris Derstroff, and Tola Minkoff for their suggestions and assistance.

* Department of Operations Research, Stanford University, Stanford, Calif. 94305.

** International Institute for Applied Systems Analysis, A-2361, Laxenburg, Austria.

Table 1. Number of Responses—IEW Regions

	IEW Regions	*Number of Responses*
1	USSR and Eastern Europe	11
2	China and other Asian Planned Economies	10
3	Centrally Planned Economies	10
4	OECD	28
5	OPEC	23
6	NODC (Non-OPEC Developing Countries)	20
7	Market Economies, Subtotal	22
8	World, Total	17
9	Individual countries/regions, not elsewhere classified	187
	Total	*328*

The poll responses are grouped according to a standardized list of eight world regions and a large miscellaneous category (individual countries/regions). Table 1 shows the identification of these regions and the number of responses that were received for each. By comparison with the 1981 poll, there has been a significant improvement in IEW coverage of the centrally planned economies and the developing countries. In this brief summary report, we cannot do justice to each of the 328 poll responses that have been received. We can only report our preliminary impressions.

The poll does not require a participant to provide all items shown in Table A-1. Thus, far more responses were received for 1980–2000 than for the year 2010. This suggests that most of these analyses are concerned with short-and intermediate-run decisions (e.g., specific investment projects), rather than with long-term questions (e.g., resource depletion, global carbon dioxide emissions, and technology development). Each type of decision requires a somewhat different time horizon and level of detail.

Table 2 summarizes the total number of responses received for each category. Most participants provided projections of GNP, total primary energy and oil consumption, but fewer included details on the other primary energy sources: natural gas, coal, hydroelectric, geothermal, and nuclear. A still smaller number of the respondents provided estimates for "solar and other renewables." In some instances, estimates for this category were combined with hydroelectric, geothermal, and other sources of energy. Item 17 (electricity generation) was added to the poll at a late date. This may explain why there has been a fairly low response rate on this item. An alternative explanation may be that electricity is "secondary" rather than primary energy, and is therefore not analyzed explicitly in all international energy projections.

Among the 78 respondents, there are governmental and international agencies, oil companies, research institutes, universities, and individuals.

IEW Regions

	Number of Responses
	11
omies	10
	10
	28
	23
ntries)	20
	22
	17
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	328

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d technology development). Each type
ferent time horizon and level of detail.
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ydroelectric, geothermal, and other
ːty generation) was added to the poll at
ıere has been a fairly low response rate
ɔlanation may be that electricity is
ɜnergy, and is therefore not analyzed
projections.
e are governmental and international
stitutes, universities, and individuals.

Table 2. Total Number of Responses[a]

	1980	*1990*	*2000*	*2010*
Number of entries for each item:				
International price of crude	220	197	197	72
Real GNP (or GDP)	251	219	223	73
Total PE consumption	265	233	244	68
Total PE production	189	184	198	68
Oil consumption	274	250	244	72
Oil production	241	243	240	72
Oil exports—imports	230	247	234	69
Natural gas consumption	233	202	210	66
Natural gas production	192	187	200	66
Natural gas exports—imports	167	180	181	64
Coal consumption	233	203	212	68
Coal production	186	181	196	68
Coal exports—imports	164	177	179	65
Hydroelectric and geothermal	224	199	209	67
Nuclear energy	234	208	217	66
Solar and other renewables	127	124	125	64
Electricity generation	127	152	162	57

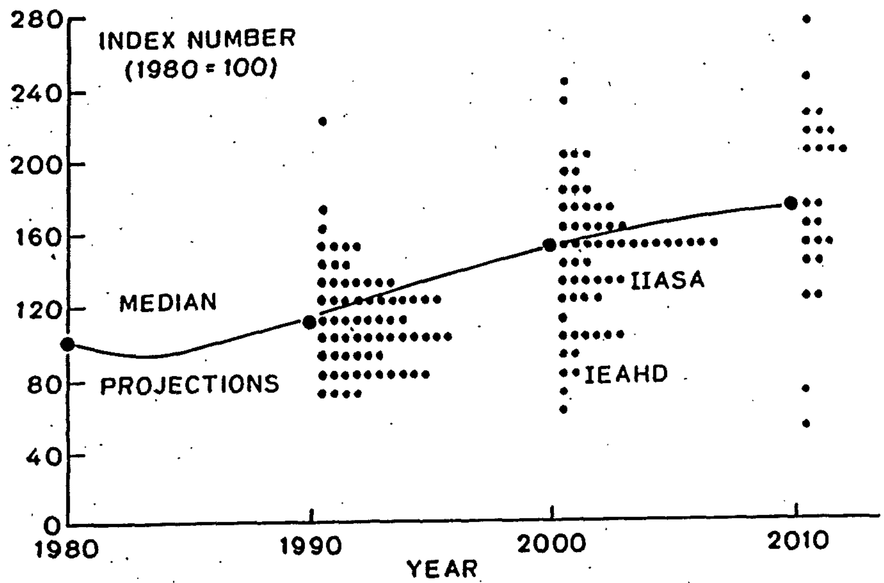
[a]Total number of responses: 328.

Both the "conventional wisdom" and minority viewpoints are represented among the groups shown in Table A-2. Each has been assigned an abbreviation containing three to five alphanumeric characters. For example, the IEA (International Energy Agency) provided both a "high demand" and a "low demand" scenario. These are denoted, respectively, by IEAHD and IEALD

Only a few of these responses are derived directly from formal models. Most are the outcome of judgment and extensive discussions within individual organizations. This type of informal process is flexible and has many other advantages but makes it difficult to trace the reasons for differences between individual projections. We cannot do justice to this issue here but hope to make some progress by the time of the next IEW meeting in June 1985.

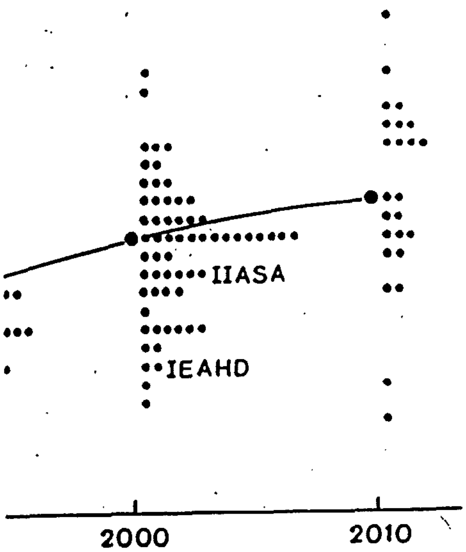
POLL RESULTS—INTERNATIONAL OIL PRICES

Taking all regions together, there are 61 independent projections of the international price of oil for the year 2000. All are reported in currency units of constant purchasing power, and as index numbers with 1980 = 100. Index numbers rather than monetary units are used for both oil prices and GNP. This avoids some definitional problems, and increases the comparability of the poll responses.



Respondent	1990	Respondent	1990	Respondent	2000	Respondent	2000	Respondent	2010
respb	223	criep	110	stols	240	criep	148	bnl	266
ipe	173	tea	109	ipe	229	DRIE	147	iemf	243
trac3	164	smil	105	dnmoe	201	DOE	146	etsld	225
stols	155	cal	102	etsld	200	czmoe	146	cerg	215
obenb	150	assu	102	cecct	199	tea	141	pilot	213
obena	150	polas	100	mkr	191	swea	141	fsz	213
etsld	150	merz	100	nzmoe	188	iiasa	139	DOE	213
ceoct	141	jaeri	100	ewrsi	182	ift	135	par	200
iiasa	139	hnpb	100	iemf	181	emcn	135	nzmoe	200
nzmoe	138	DRIE	99	fsz	181	ieald	132	criep	199
mkr	134	3rt	99	obenb	175	cal	131	opecl	196
iemf	134	ieald	98	obena	175	smil	130	jaeri	175
esc	134	cec	97	bph	175	merz	130	etshd	175
atw.	134	pilot	96	bnl	172	assu	122	assu	165
par	130	respa	94	doe	168	paec	122	tea	164
ewrsi	128	eia	94	esc	163	polas	120	smil	150
wbk	126	ece	92	3rt	161	respi	117	polas	150
swea	125	cerg	90	par	160	hnpb	110	leob	150
etshd	125	eni	86	cerg	160	bpl	105	ift	144
dnmoe	125	ceceu	86	pilot	157	iea83	103	iiasa	139
gri	125	trac2	85	emch	156	seri	100	paec	122
stohs	122	cies1	85	wbk	154	oriea	100	hnpb	120
ift	120	cies	85	smie2	154	ceceu	97	ciesl	68
bph	120	ieahd	82	smie1	154	ceccp	97	ciesh	50
fsz	119	DOE	81	gri	153	cec	93		
cecfc	118	leob	80	respa	153	cecfc	88		
trac1	116	iee	79	stohs	150	respb	84		
emch	116	bnl	78	leob	150	ieahd	82		
doe	115	iea83	77	jaeri	150	ciesl	73		
czmoe	115	ceccp	76	etshd	150	ciesh	62		
candd	110	ciesh	75	opecl	148				
paec	110	bpl	75						
opecl	110	shell	73						
emcn	110	respi	71						

Figure 1. International price of crude oil (1980 = 100).



ent 2000	Respondent	2000	Respondent	2010
240	criep	148	bnl	266
229	DRIE	147	iemf	243
201	DOE	146	etsld	225
200	czmoe	146	cerg	215
199	tea	141	pilot	213
191	swea	141	fsz	213
188	iiasa	139	DOE	213
182	ift	135	par	200
181	emcn	135	nzmoe	200
181	ieald	132	criep	199
175	cal	131	opecl	196
175	smil	130	jaeri	175
175	merz	130	etshd	175
172	assu	122	assu	165
168	paec	122	tea	164
163	polas	120	smil	150
161	respi	117	polas	150
160	hnpb	110	ieob	150
160	bpl	105	ift	144
157	iea83	103	iiasa	139
156	seri	100	paec	122
154	oriea	100	hnpb	120
154	ceceu	97	ciesl	68
154	ceccp	97	ciesh	50
153	cec	93		
153	cecfc	88		
150	respb	84		
150	ieahd	82		
150	ciesl	73		
150	ciesh	62		
148				

e of crude oil (1980 = 100).

The individual oil-price estimates differ widely—in extreme cases by a factor of three. Each estimate is shown as a dot in a frequency distribution (Figure 1). With only a few exceptions, the respondents indicated that real oil prices will rise from their 1980 level—and at a more rapid rate during the 1990s than during the 1980s. Typically, this reflects the view that those forces leading to price increases (demands increased by economic growth and supplies reduced because of the gradual exhaustion of conventional oil and gas resources) will be stronger than those exerting downward pressure on oil prices (conservation responses to the events of the 1970s and the introduction of alternative forms of energy supply). The median value of all responses is 148 in 2000, equivalent to an average annual price increase of 2.0 percent from 1980 onward. Clearly this result is incompatible with the view that the 1983 oil glut was a "structural" phenomenon, and that low prices will persist indefinitely.

With a little detective work, it is possible to narrow the range of the possibilities considered here. For example, one of the lowest responses is IEAHD. This represents a "what if?" scenario. The IEA assumes that real oil prices will decline between 1980 and 1985, and then will remain stable through 2000. Under these circumstances, oil demand is stimulated and begins to exceed supplies during the 1990s. This represents an instructive thought experiment showing the consequence of "too low" an oil price, but it is not a logically consistent scenario. By contrast, consider the same organization's low-demand case (IEALD). Through side calculations, it can be shown that the IEA's global supply–demand gap would have been reduced to zero if the agency had assumed a price level that is close to the poll median results.

Here is a second example of analytic structure determining the poll response. Underlying IIASA's 1981 publication *Energy in a Finite World* was a good deal of optimism on the costs and speed of market penetration of synthetic fuels. It was believed that tar sands, shale oil or coal-based synfuels could expand rapidly in North America, and that their costs would be about 40 percent higher (in real terms) than the 1980 price of crude oil. This explains why IIASA's initial poll response (the "low" scenario of 1981) indicates a 1990 crude-oil price index of 139 (with 1980 = 100) and why the index remains at that level through 2010. In effect, synthetic fuels serve as an international "backstop" technology in the original study. This leads to stable world oil prices—and no increase in the OECD region's net demand for oil imports. More recent IIASA calculations (identified as IIA83) have arrived at somewhat different conclusions.

Through the IEW process, we hope to systematize this type of analysis. Each participant is urged to provide conjectures as to why stated projections deviate from the poll medians. Some of the deviation may turn out to be errors in reporting or transcription. Others may be connected with definitional differences in regional or product coverage. In other cases, there may be explanations that can be related directly to model structure. Another round of polls and discussions would help to distinguish the effects of assumptions, statistical categories, and analytic features.

Cynics will be quick to point to other possible explanations for these differences. Long-term projections may be heavily influenced by current events. For example, there was an oil glut during the 18 months that elapsed between the 1981 and 1983 workshops. Between these two polls, the median oil-price projection for the year 2000 declined from 175 to 148 (in real terms, with 1980 = 100). The statistical significance of this result is a bit doubtful, because the sample was not identical in both cases. Moreover, one would expect this type of decline if oil prices are following a random-walk pattern. Through autocorrelation, projected prices are then affected by the current level. Nonetheless, the cynics may be right. Just as in macroeconomic forecasting, there is a strong herd instinct that operates within the community of energy analysts. In any case, the workshop process is bound to lead to healthy introspection—and more attention to minority viewpoints.

IMPORTS AND EXPORTS—OIL AND GAS

Because oil is a liquid, it can be transported at lower specific costs than either natural gas or coal. Until the distant future date when there are large-scale movements of methanol and/or hydrogen, it is generally believed that oil will retain its present position as the principal fuel in international trade. Because oil constitutes a "swing" fuel, small differences in a region's total energy production or consumption can lead to large percentage changes in the quantities of oil imported or exported.

Measurement problems turn out to be quite serious when we attempt to compare oil import and export projections. Within the OECD region, for example, there are wide discrepancies between the individual responses for the statistical base year of 1980 (Figure 2). These differences account for some of the range in import projections in subsequent years. The discrepancies in measurement are probably more significant than the changes in the median. It would be useful to determine how much of these differences can be traced to statistical difficulties in distinguishing between crude oil and refined products, and how much is attributable to other factors, such as processing losses, stock changes, and bunkers.

Figure 3 summarizes the workshop's median estimates of interregional shipments of oil and gas. (Coal shipments are insignificant at this level of regional aggregation. A more detailed geographical breakdown is needed in order to analyze coal trade.) The poll provides an automatic global

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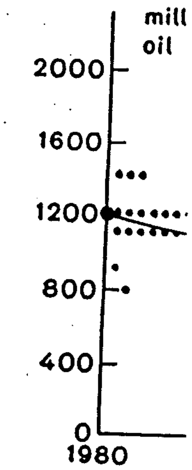

Respondent	198(
sohn	1442
stols	136C
stohs	1360
opecl	1210
DOE	1185
ipe	1181
cerg	1181
ieald	1180
ieahd	1180
iea83	1180
bpl	1171
bph	1171
gulfb	1170
wbk	1155
ind	1155
eni	1148
con	1144
respc	1135
respb	1112
respa	1112
3rt	1085
oriea	876
iiasa	797

product coverage. In other cases, related directly to model structure. would help to distinguish the effects and analytic features.

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OIL AND GAS

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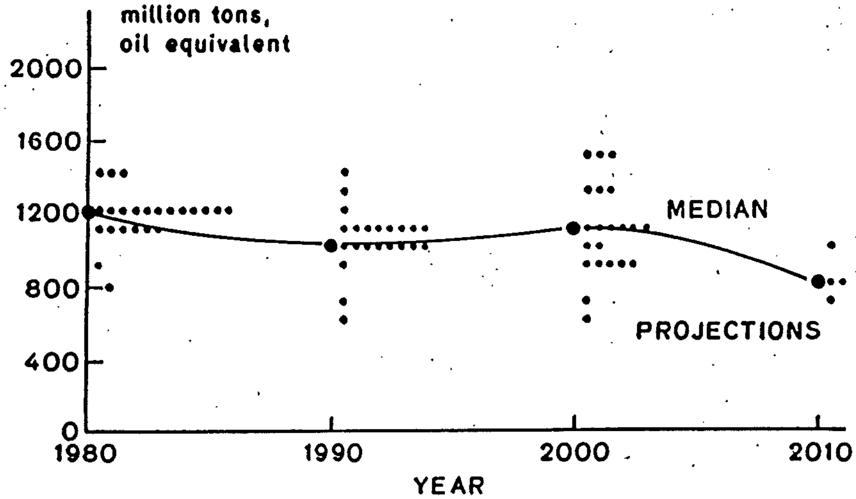
median estimates of interregional nts are insignificant at this level of geographical breakdown is needed poll provides an automatic global consistency check between independent estimates of interregional trade. From the positive and negative entries in Figure 3, we find that the export and import totals are in reasonably close balance. Looking at the poll responses on a nation-by-nation basis, however, there is evidence that the growth in NODC oil imports may be understated.



Respondent	1980	Respondent	1990	Respondent	2000	Respondent	2010
sohn	1442	stohs	1395	aohn	1499	opecl	1050
stols	1360	sohn	1253	oriea	1475	iiasa	842
stohs	1360	bph	1190	ieahd	1454	cerg	805
opecl	1210	ieahd	1140	stohs	1310	DOE	725
DOE	1185	gulfb	1125	gulfb	1285		
ipe	1181	respa	1112	bph	1267		
cerg	1181	wbk	1109	opecl	1145		
ieald	1180	opecl	1107	ind	1145		
ieahd	1180	eni	1094	wbk	1122		
iea83	1180	stols	1090	iea83	1113		
bpl	1171	iea83	1068	con	1087		
bph	1171	DOE	1025	ipe	1056		
gulfb	1170	cerg	1020	cerg	993		
wbk	1155	ipe	1015	3rt	980		
ind	1155	respc	1010	DOE	935		
eni	1148	ind	1010	respa	896		
con	1144	con	995	stols	875		
respc	1135	ieald	975	ieald	872		
respb	1112	bpl	974	bpl	872		
respa	1112	3rt	940	iiasa	726		
3rt	1085	iiasa	712	respb	613		
oriea	876	respb	608				
iiasa	797						

Figure 2. OECD oil imports (mtoe).

During 1980, the CPE (centrally planned economies) maintained net exports of oil to the market economies, but these quantities were quite small in relation to OPEC's export volume. According to most of the poll participants, there will be a declining trend of net oil exports from the CPE, and they might become net importers of oil by the year 2000. Even at that point, the CPE will be largely self-sufficient in energy, and will substantially increase their gas exports to the OECD. International energy markets will continue to be dominated by the oil trade between just regions—OPEC and the OECD.

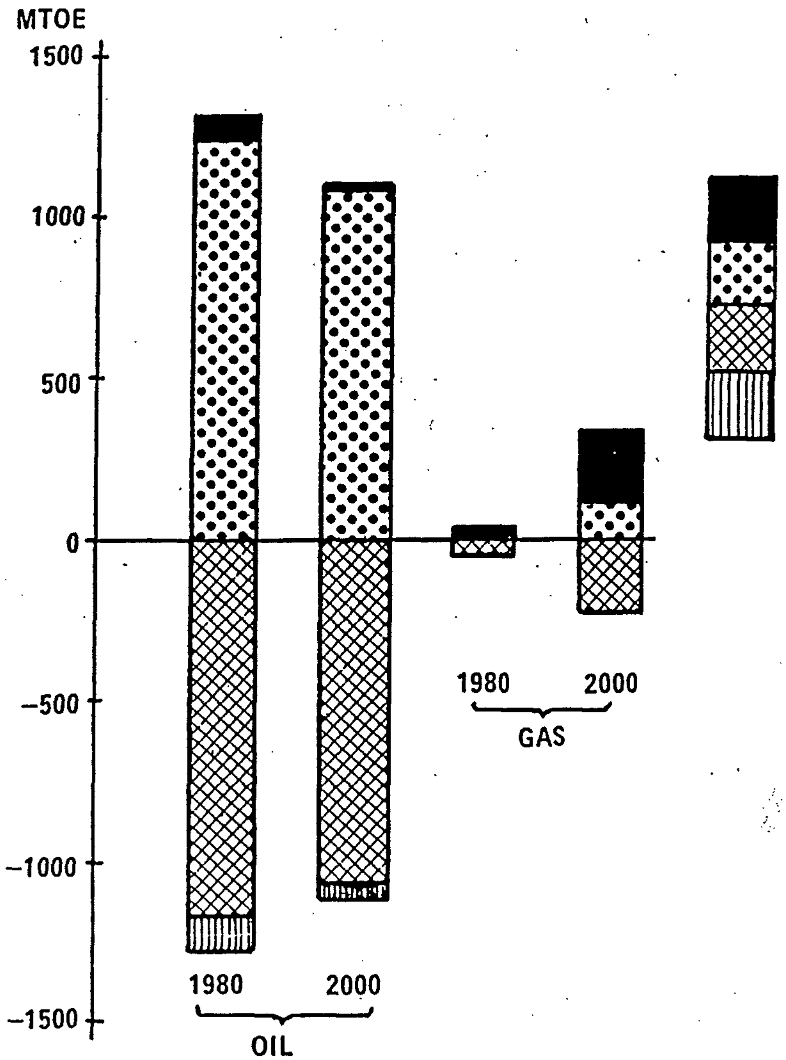


Figure 3. Exports–imports of oil and gas (mtoe).

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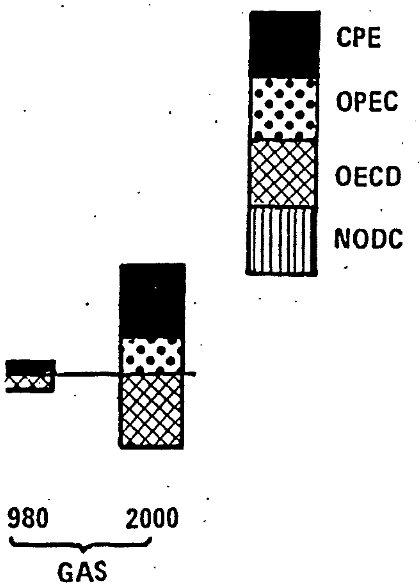

s of oil and gas (mtoe).

NODC (non-OPEC developing countries) oil imports will depend upon their income growth and their balance-of-payment constraints. There is a diversity of opinion on whether these countries will choose to expand their domestic oil production, or whether they will shift to less energy-intensive lines of development than in the past. Very few of the poll participants have projected that the NODC group as a whole will be importing significantly more oil in the year 2000 than in 1980. The median indicates a decline. In assessing the significance of these results, it would be helpful to have more analysis undertaken by the NODCs themselves. Their research organizations are underrepresented within the poll.

ENERGY CONSERVATION, INTERFUEL SUBSTITUTION, AND RENEWABLE ENERGY

Figures 4 and 5 provide a global view of the median poll responses for 1980 and 2000 on total primary energy consumption and its breakdown into individual fuels. Each pair of bar charts summarizes one region's prospects for interfuel substitution and for energy conservation. These forces do not operate in an autonomous way. They are a direct consequence of the two oil-price shocks of the 1970s—together with the expectation of further oil-price increases.

Except for OPEC, it is projected that total primary energy demands will increase less than in proportion to economic growth. Conservation is defined here as a residual—the difference between the projected energy consumption in 2000 and the demands that would have occurred if the energy–GNP ratio had remained constant from 1980 on. Thus, conservation represents the combined effect of improved technical efficiencies and of changes in the economy's product mix.

The overall reduction in the energy–GNP ratio (expressed in terms of primary energy equivalent) is indicated by the conservation component at the top of each region's bar for the year 2000. In both centrally planned and market economies, *conservation* represents the largest single source of additional energy supplies for 2000. This was once a heresy, but is apparently the prevailing view today.

Interfuel substitution plays a vital role in explaining why virtually all organizations project significant GNP growth, despite little or no increase in global oil supplies. Natural gas, coal, and nuclear energy provide the principal sources of interfuel substitution, although their relative contributions vary from one respondent to another. A major increase in natural gas production is anticipated only within OPEC and the USSR.

There is general agreement that only a small contribution will be provided by the *renewables:* hydroelectric, solar, and biomass. This outcome of the poll may be attributed to the inherent limitations of technologies based on dispersed energy sources. It may also be attributed to definitional differences, because the 1980 base year responses vary quite erratically from one respondent to another. Clearly, it would be worthwhile to standardize these definitions and statistics. In any event, the IEW poll cannot be expected to resolve the highly charged controversy surrounding the renewables and the role that they might play as alternatives to coal and nuclear energy.

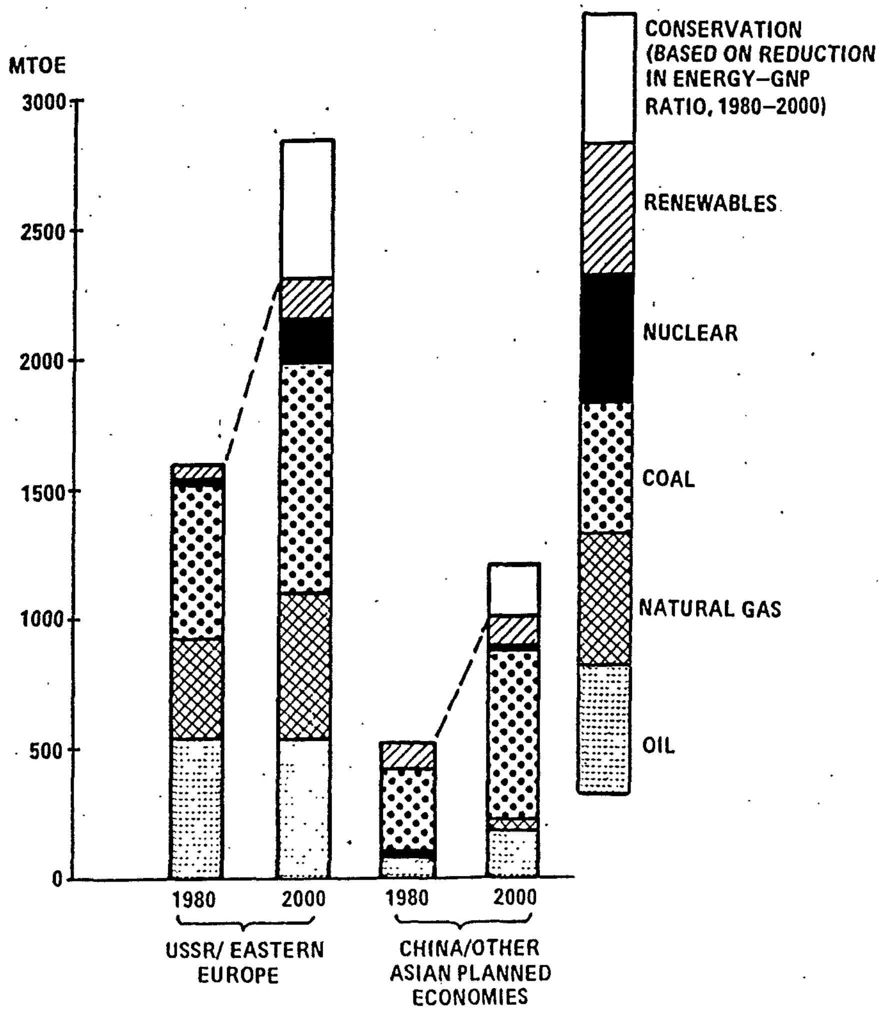

Figure 4. Total primary energy consumption—poll medians—centrally planned economies (mtoe).

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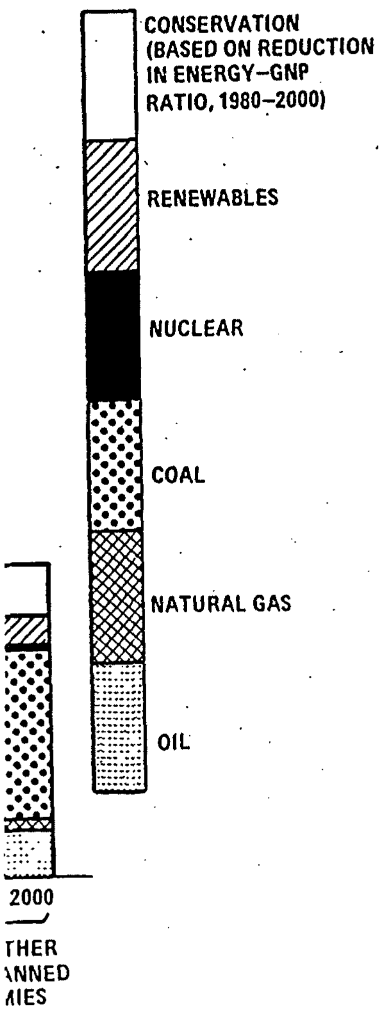

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WHY DO ENERGY PROJECTIONS DIFFER?

The following list offers reasons why energy projections may differ from one another. *No single factor explains all of the differences.*

Errors in recording and transcribing;
1980 statistics;
Date of projection;
Time horizon of projection;
Definitional problems;
Model structure;
Demand parameters, such as GNP growth, structural changes, regulatory approaches to conservation, price and income effects, final vs. primary energy demands, and the role of electricity;
Supply parameters, such as conventional resources (geological resource base, producibility constraints) and unconventional fuels (costs and speed of market penetration;
Philosophical differences, and
"Stake-Holders": detailed information vs. inherent biases.

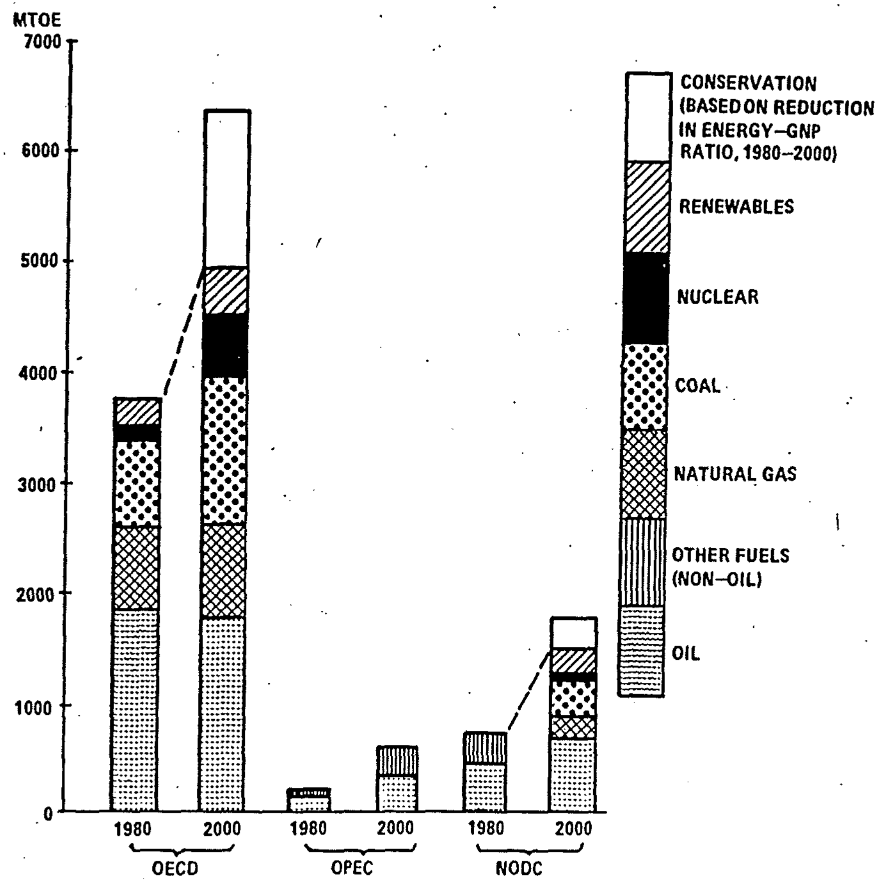

Figure 5. Total primary energy consumption—poll medians—market economies (mtoe).

First, there can be *errors* in recording and transcribing the poll entries. We have tried to be vigilant about this. Although confident that transcription errors are not a significant source of the differences reported here, we cannot guarantee to have detected all errors. Iterative polling can be helpful in identifying errors, and in reducing the differences between base-year (1980) statistical measurements.

The *date of projection* is a crucial element in attempting to understand why these estimates differ. Recent forecasters are not necessarily wiser than earlier ones, but at least they can take advantage of autocorrelation in the random-walk pattern that seems characteristic of energy time series.

The *time horizon of the projection* may also be a significant element. There is some evidence that the longer the time horizon, the lower the forecast of the total level of energy demands and the higher are oil prices.

Definitional problems are a major source of the discrepancies between individual projections. It is disturbing to see the wide range of variations in base-year (1980) statistics. Some of these variations are attributable to differences in the date of projection.

It is an open issue whether model *structure* (whether formal or implicit) can explain a large part of the variation in poll responses. Our personal conjecture is that far less is explained by structure than by differences in the numerical assumptions related to supply-and-demand scenarios. Additional work is needed in order to check this conjecture.

Uncertainties in GNP growth are frequently cited as a critical element in *demand* forecasting. Over the long term, however, these may be less significant than differences in price elasticities of demand, or in the response of individual energy consumers to centralized regulations that are designed to conserve energy.

Scenario assumptions may be equally critical on the *supply* side of international energy markets. Over the next two decades, it is not the ultimate resource base, but rather the producibility constraints (e.g., leasing and depletion policies) that will determine how rapidly the world's nonrenewable resources will be exploited. Moreover, international crises and supply disruptions may occur at any moment. These events cannot easily be predicted by conventional economic analysis.

In all of this, perhaps the most elusive factors are philosophical and ideological. "Stake-holders" have more detailed information available, but have an obvious interest in exaggerating the prospective rate of market penetration by their group's specific technology. Similarly, political leaders are prone to adopt optimistic targets for their nation's or region's GNP growth. Another factor is the personality of the individual forecaster. Some have an inclination to focus upon good news, and others prefer to predict that doomsday is at hand. (These two attitudes seem to be the psychological opposite of the "herd instinct.")

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In short, there are many imponderable elements that may even unconsciously influence projections. But we also believe the converse to be true—that the IEW may exert an influence on these factors. The polling process cannot eliminate biases, but can at least contribute to greater awareness of their existence.

On balance, we believe that long-term energy projections are essential for both the public and private sectors of the world's economies. Rational decisions cannot be based on scenarios that fail the test of logical consistency. Individual projections will continue to differ, but it is worthwhile to attempt to understand why.

POSTSCRIPT ON THE DELPHI TECHNIQUE

The Delphi technique and the IEW process have elements in common, but there are distinct differences. Both entail iterative polling, which may lead to "cuing" and to an artificial consensus. And there may be unconscious biases in the selection of poll participants.

There are, however, the following key differences:

1. The IEW poll does not ask respondents for their personal opinions, but rather for their organization's most recent set of published projections. Written documents provide a more objective record than informal opinions and thereby make a systematic difference in the results.
2. Each respondent is asked to fill in a supplementary questionnaire that is designed to elicit information on the method of projection, reasons for differences from poll medians, and critical uncertainties in the international energy outlook. Again, this enhances the reproducibility of poll results.
3. Except for a few cases where anonymity is essential (e.g., as a consequence of US antitrust laws), the individual poll respondents are identified.
4. Face-to-face meetings are an essential part of the IEW process.

Workshop sessions are more expensive than remote polling, but these meetings appear far more effective in identifying the reasons for differences in projections. On international energy issues, it is just as important to understand these differences as to arrive at a logically consistent consensus. And we cannot expect any certainty other than the inevitability of surprise.

APPENDIX TABLES

A-1. IEW poll form, IIASA, 1983
A-2. IEW poll respondents

Other appendix tables, frequency distributions of region-by-region energy-GNP ratios, identification of individual countries/regions, individual response forms, and frequency distributions of responses are available in the form of a computer printout (approximately 600 pages) and a magnetic tape. For further information, please write to Leo Schrattenholzer at IIASA. Frequency distributions are also available for individual countries/regions.

Table A-1. Inter
Country/Region:
Organization/pro
Reference (incluc

Index numbers, constan *1980 = 100:*
1. International price Arabian Light)
2. Real GNP (or GDP)
Primary energy, million equivalent (mtoe)[a]
3. Total consumption
4. Total production
5. Oil, consumption[b]
6. Oil, production[b]
7. Oil, exports—impo
8. Natural gas, consur
9. Natural gas, produc
10. Natural gas, export
11. Coal, consumption
12. Coal, production[c]
13. Coal, exports—imp
14. Hydroelectric and g
15. Nuclear energy
16. Solar and other renc
17. Electricity generatio

[a]Useful approximations

[b]Oil includes natural ga shale oil.

[c]Coal includes solid fuel synthetic fuels.

.cy distributions of region-by-region of individual countries/regions, indi- :y distributions of responses are avail- .tout (approximately 600 pages) and a ation, please write to Leo Schratten- utions are also available for individual

Table A-1. International Energy Workshop Poll, IIASA, 1983

Country/Region: ______________________

Organization/project: ______________________

Reference (including date) of most recent report: ______________________

	1980	1990	2000	2010
Index numbers, constant purchasing power; 1980 = 100:				
1. International price of crude oil (e.g. Arabian Light)	100			
2. Real GNP (or GDP)	100			
Primary energy, million tons of oil equivalent (mtoe)[a]				
3. Total consumption				
4. Total production				
5. Oil, consumption[b]				
6. Oil, production[b]				
7. Oil, exports—imports[b]				
8. Natural gas, consumption				
9. Natural gas, production				
10. Natural gas, exports—imports				
11. Coal, consumption[c]				
12. Coal, production[c]				
13. Coal, exports—imports[c]				
14. Hydroelectric and geothermal				
15. Nuclear energy				
16. Solar and other renewables				
17. Electricity generation (tkWh)				

[a]Useful approximations: 1 mtoe/year = 10^{13} kilocalories
0.65 mtoe/year = 1 million tons coal/year
50 mtoe/year = 1 million barrels daily
23 mtoe/year = 1 quad BTU/year

[b]Oil includes natural gas liquids, unconventional oils, and synthetics based on tar sands and shale oil.

[c]Coal includes solid fuels such as lignite and peat. Includes coal consumed for manufacture of synthetic fuels.

Table A-2. IEW Poll Respondents

Organization/project		Last Year Reported	Country/Region Coverage
ASSU	Academy of Sciences of the USSR, June 1983	2010	USSR
ATW	Forschungsgesellschaft für alternative Technologien und Wirtschaftsanalysen (ATW), University of Regensburg, October 1982	1990	Brazil, India, Kenya, Malaysia
BNL	Brookhaven National Laboratory, 1983 (forthcoming)	2010	U.S.A.
BPH, BPL	British Petroleum—high- and low-growth cases, December 1982	2000	4–7; OECD Europe
BPPTK	Badan Pengkajian dan Penerapan Teknologi (BPP Teknologi), December 1980	2010	Indonesia
CAL	Standard Oil Company of California, June 1982	2000	4
CANDD	CANDIDE Model, Economic Council of Canada, September 1982	1990	Canada
CECCP, CECEU CECFC, CEC, CECCT	Commission of the European Communities—Cooperation, Europe, and Free Competition scenarios, and results identical for all 3 scenarios, June 1983; Candidate Technologies scenario, March 1982	2000	Belgium, Denmark, Federal Republic of Germany, France, Greece, Ireland, Italy, Luxembourg, The Netherlands, United Kingdom
CERG	Cambridge Energy Research Group (UK), R. J. Eden,	2010	4–7; U.S.A. and Canada; Japan, Australia and New Zealand; Western Europe
CIES, CIESH, CIESL	Center for International Energy Studies, Erasmus University—OECD Europe, high-, and low-growth estimates, August 1982	2010	8; OECD Europe
CON	Conoco, January 1983	2000	4, 7; U.S.A.
CPC	Chinese Petroleum Corporation, February 1982	2000	Taiwan
CRIEP	Central Research Institute of Electric Power Industry, 1982	2010	Japan
CZMOE	Czechoslovakian Federal Ministry of Fuel and Energy, 1983	2000	Czechoslovakia
DNMOE	Danish Ministry of Energy, 1983	2000	Denmark
DOE82	U.S. Department of Energy, Office of Policy, Planning, and Analysis, and Analysis, July 1982	2000	5, 7
DOE	U.S. Department of Energy, Office of Policy, Planning, and Analysis, July 1983	2010	3, 4, 6; U.S.A.

Last Year Reported	Country/Region Coverage
2010	USSR
1990	Brazil, India, Kenya, Malaysia
2010	U.S.A.
2000	4–7; OECD Europe
2010	Indonesia
2000	4
1990	Canada
2000	Belgium, Denmark, Federal Republic of Germany, France, Greece, Ireland, Italy, Luxembourg, The Netherlands, United Kingdom
2010	4–7; U.S.A. and Canada; Japan, Australia and New Zealand; Western Europe
2010	8; OECD Europe
2000	4, 7; U.S.A.
2000	Taiwan
2010	Japan
2000	Czechoslovakia
2000	Denmark
2000	5, 7
2010	3, 4, 6; U.S.A.

Table A-2. IEW Poll Respondents (Continued)

Organization/project		Last Year Reported	Country/Region Coverage
DRIE	DRI Europe, March 1983	2000	Western Europe
ECE	U.N. Economic Commission for Europe, General Energy Unit and Projections and Programming Division, 1982	1990	USSR; Western Europe, Eastern Europe, North America, Total of ECE Regions
EEF	U.N. Economic Commission for Europe, General Energy Unit, "An Efficient Energy Future," March 1983	2000	1; U.S.A
EIA	U.S. Energy Information Administration, 1990 Midprice Scenario, 1983	1990	4, 5, 7; U.S.A.; Non-U.S.OECD, Developing Countries
EMCH	ETA–MACRO: China; A.S. Manne, Stanford University November 1982	2000	2
EMCN	ETA–: Canada; J.S. Rogers and T.F. Wilson, University of Toronto, May 1983	2000	Canada
ENI	Ente Nazionale Idrocarburi (ENI), 1983	1990	4
ESC	Energy Study Centre, January 1983	2000	The Netherlands
ETSHD, ETSLD	Energy Technology Systems Analysis Project of the International Energy Agency—High- and low-demand cases, 1983 (forthcoming).	2010	Australia, Austria, Belgium, Federal Republic of Germany, Ireland, Italy, Japan, The Netherlands, Norway, Spain, Sweden, Switzerland, United Kingdom, United States; Sum of the above 14 countries
EWRSI	The East–West Center, Resource Systems Institute, Energy and Industrialization Project, 1982	2000	Bangladesh, India, Pakistan, Papua New Guinea, Philippines, Singapore, South Korea, Sri Lanka, Thailand
FSZ	J.D. Fuller, S.D. Schwartz, and W.T. Ziemba, University of British Columbia, Fall 1982	2010	Canada
GRI	Gas Research Institute, September 1983	2000	U.S.A.

Table A-2. IEW Poll Respondents (Continued)

Organization/project		Last Year Reported	Country/Region Coverage
GULFB, GULFS, GULFL	Gulf Oil Corporation, Economics Division—Baseline, Supply Disruption and Low Economic Growth scenarios, February 1983	2000	4–7; U.S.A., Canada, Japan; Western Europe, Developing Countries
HNPB	Hungarian National Planning Board—Energy Modeling Group, 1983	2010	Hungary
IAEAH, IAEAL	International Atomic Energy Agency—high- and low-consumption estimates, September 1982	2000	1, 4, 8; OECD North America, OECD Europe, OECD Pacific, Asia, Latin America, Africa and Middle East; Industrialized Countries; Developing Countries
IEA, IEAHD, IEALD	International Energy Agency—Midpoints, high- and low-demand scenarios, October 1982	2000	4–6; USSR
IEA83	International Energy Agency—Low-demand scenario, June 1983	2000	4
IEE	Institute of Energy Economics, Japan, December 1982	1990	Japan
IEMF	Israel Energy Modeling Forum, July 1982	2010	Israel
IFT	Institute for Future Technology, 1982	2010	Japan
IIASA, IIA83	International Institute for Applied Systems Analysis, 1981; also 1983	2010	1–4, 7–8; Aggregate of IIASA regions 4 and 5, IIASA region 6
IND	Standard Oil Company of Indiana, May 1983	2000	1–8; Aggregate of Israel, Yugoslavia, and South Africa
INET	Institute of Nuclear Energy Technology, Quinghua University, Beijing, December 1981	2000	2
IPE	IPE Model; N. Choucri, Massachusetts Institute of Technology, 1982	2000	4–7; U.S.A. Japan; Western Europe
JAERI	Japan Atomic Energy Research Institute, March 1983	2010	Japan
LEOB	J.J. Schmidt, University of Mining and Metallurgy, Leoben, 1983	2010	8
LOVNS	A. and H. Lovins, Rocky Mountain Institute, June 1982	2000	8

Last Year Reported	Country/Region Coverage
2000	4–7; U.S.A., Canada, Japan; Western Europe, Developing Countries
2010	Hungary
2000	1, 4, 8; OECD North America, OECD Europe, OECD Pacific, Asia, Latin America, Africa and Middle East; Industrialized Countries; Developing Countries
2000	4–6; USSR
2000	4
1990	Japan
2010	Israel
2010	Japan
2010	1–4, 7–8; Aggregate of IIASA regions 4 and 5, IIASA region 6
2000	1–8; Aggregate of Israel, Yugoslavia, and South Africa
2000	2
2000	4–7; U.S.A. Japan; Western Europe
2010	Japan
2010	8
2000	8

Table A-2. IEW Poll Respondents (Continued)

Organization/project		*Last Year Reported*	*Country/Region Coverage*
MERZ	N. Merzagora, Economic Analysis Division, ENEA, June 1983	2000	Italy
MKR	S.K. Mukherjee and S.H. Rahman, November 1982	2000	India
NGODP	International Natural Gas Study, Harvard University, and the OPEC Downstream Project, East–West Center, B. Mossavar-Rahmani and F. Fesharaki, 1983	1990	5; Algeria, Ecuador, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, Venezuela
NRMPE	Norwegian Royal Ministry of Petroleum and Energy, 1982	1990	Norway
NZMOE	New Zealand Ministry of Energy, August 1982	2010	New Zealand
OBENA, OBENB	Observatoire de L'Energie—Scenarios A and B, January 1983	2000	France
OEWAG	Österreichische Elektrizitätswirtschafts-AG (Austrian Electric Company), 1982	2000	Austria
OLADA, OLADB	Organización Latinoamericana de Energía (OLADE)—Scenarios A and B, 1983	2000	Latin America
OPECD, OPECL	Organization of Petroleum Exporting Countries (OPEC)—Domestic Energy Requirements and Long-Term Energy Models, 1983 (forthcoming).	2010	4–7
ORIEA	Oak Ridge Institute for Energy Analysis, 1982	2000	1–8
PAEC	Pakistan Atomic Energy Commission, December 1982	2010	Pakistan
PAR	J. Parikh, International Institute for Applied Systems Analysis, 1982	2010	India
PIEEM	Potential for Industrial Expansion Energy Model; Energy Studies Unit, University of Strathclyde, Scotland, October 1982	2010	8
PILOT	PILOT Energy-Economic Model; P. H. McAllister and J. C. Stone, Stanford University, December 1982	2010	U.S.A.
POLAS	Energy Problems Committee, Polish Academy of Sciences, July 1982	2010	Poland

Table A-2. IEW Poll Respondents (Continued)

Organization/project		*Last Year Reported*	*Country/Region Coverage*
RESPA	Respondent A, January 1983	2000	3–7
RESPB	Respondent B, January 1983	2000	3–7
RESPC	Respondent C, 1982	1990	4–7
RESPH	Respondent H, 1983	2000	Japan
RESPI	Respondent I, 1983	2000	7; U.S.A. Japan; Developing Countries, Western Europe
SERI	Solar Energy Research institute—Lawrence Berkeley Laboratory, 1981	2000	U.S.A.
SHELL	Shell International, London, June 1983	2000	7
SMIE1, SMIE2	Spanish Ministry of Industry and Energy (MINER)—Scenarios 1 and 2, 1983	2000	1, 2, 8; Japan; Western Europe, U.S.A. and Canada, Latin America, Africa, Middle East, Aggregate of South Asia, Southeast Asia, and Australasia
SMIL	V. Smil, University of Manitoba, 1983	2010	2, 8
SOHN	I. Sohn, New York University, December 1982	2000	1–8
STOHS, STOLS	R. Stobaugh—high- and low-energy supply cases, May 1982	2000	4–6
SWEA	Swedish Energy Agency, June 1983	2000	4
TEA	J. Brady, National Board for Science and Technology, Ireland, April/May 1983	2010	Ireland
TRAC1, TRAC2, TRAC3	Tractionel–Scenarios 1, 2, and 3, July 1982	1995	Belgium
UNIDO	United Nations Industrial Development Organization (UNIDO), February 1983	1990	2; Japan; North America, Western Europe, Eastern Europe, Latin America
WBK	World Bank, July 1982	2000	1–8
WECHG, WECLG	World Energy Conference (WEC)—Preliminary projections, 1983 (forthcoming)	2000	3, 7, 8; Developing Countries (5 + 6)
3RT	3RT Model; A.S. Manne and P.V. Preckel, Stanford University, March 1983	2000	4–7