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Project Independence Report: A Review of U.S. Energy Needs Up To 1985

by

Jerry A. Hausman
Department of Economics, M.I.T.

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The Project Independence Report (PIR) is the result of an intensive six month effort by the Federal Energy Administration (FEA) to construct a comprehensive economic model to evaluate current and projected energy conditions in the U.S. over the period 1973-1985. The model is the first large scale economic model which attempts to integrate macroeconomic factors with the key microeconomic fact which must be recognized in any successful energy model, the depletable nature of energy supplies. The PIR model thus represents an extension of previous econometric models which are based on a constant returns technology. The PIR attempts to model explicitly the discovery and extraction process for oil, natural gas, and coal and then to include this process in a larger model of refining and production for final demand. Another advance of the PIR is the combination of econometric models with engineering models and a mathematical programming model rather than relying solely on one type of modelling procedure. While many individual segments of the PIR model have serious faults, the overall framework provides an excellent system for drawing together the extremely complex and interdependent sectors of the U.S. energy system. With further work by the FEA to correct the model's deficiencies, the final product could provide an integrated framework for evaluating energy policy.

In addition to the energy model, the PIR considers many energy connected matters including an environmental assessment, ar international assessment,

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I would like to thank my colleagues on the Energy Policy Studies Group at M.I.T., especially Robert Hall (macroeconomics), Paul Joskow (electric power), and Paul MacAvoy (gas and oil supply), for helpful discussions. Also, William Hogan of the FEA has been helpful in clarifying many problems.

and the role of research and development in providing new energy sources beyond the year 1985. Also, in evaluating U.S. energy needs over the 1973-1985 period the effects of conservation programs and demand management are evaluated. Since the PIR is a multi-volume document containing too many topics to be treated in one article, I plan to concentrate on the PIR energy model.[1/]

The model attempts to answer the question which underlies all energy policy discussions: given projections of macroeconomic growth over 1973-1985 what are the likely levels of U.S. energy demand and supply and resulting energy imports? An assumption maintained throughout is that the U.S. faces a perfectly elastic supply for oil in the world market at each of the exogenously set prices studied in the PIR. The answer of the PIR for the base year 1985 is that the U.S. will remain heavily dependent on foreign imports in the three main oil price scenarios considered. The three price scenarios considered are $4 per barrel oil, $7 per barrel oil, and $11 per barrel oil (in 1973 prices). For the "Business As Usual" (BAU) case the FEA forecasts:

1985 BAU:	Oil Imports (million barrels per day)
$ 4	21.4 mbd
$ 7	12.4 mbd
$ 11	3.3 mbd

While many conflicting biases are present in the FEA model, my main conclusion is that these forecasts overstate the likely level of U.S.

[1/] A more extensive analysis of the complete PIR is contained in the M.I.T. Energy Policy Study Group Report [15].

oil imports. After accounting for the most important bias, a severe underestimate of natural gas consumption and natural gas price, and attempting to adjust for other biases, my best guess is that the U.S. is more likely to be self-sufficient in energy than the FEA indicates at $11 per barrel oil; and at lower oil prices imports are likely to be smaller than forecast by the <u>PIR</u>. In reviewing the <u>PIR</u>, I will attempt to point out the biases which lead me to this more optimistic forecast (with respect to imports) than the forecast of the FEA.

The plan of this paper is first to give an overview of the energy model, including its interaction with macroeconomic factors and the key policy assumptions. Then in Section 2, I turn to an evaluation of the main sources of supply of domestic energy: oil, natural gas, coal, and electricity and nuclear power. Separate models for each energy source are used in the <u>PIR</u>, and I discuss the modelling technique as well as potential biases contained in the supply forecasts. In Section 3 the energy demand model and its interaction with the integrating (equilibrium) model are discussed. Lastly, the most important shortcomings of the <u>PIR</u> model are outlined with suggestions made for future improvements. As an initial attempt, the <u>PIR</u> model represents a significant advance over previously existing models to evaluate energy policy and with further work can provide an important and much needed policy evaluation tool.

1. Policy Assumptions and Framework of the PIR Model

Policy Assumptions:

In attempting to forecast energy demand and supply over a 12 year period it is necessary to make assumptions about the likely evolution of U.S. energy policy. Needless to say, the forecasts will be conditional on these policy assumptions, and any change in policy could seriously affect the results. A shortcoming of the *PIR* is the failure to make alternative forecasts under widely differing policy assumptions; while the FEA is certainly aware of the importance of the assumptions, sufficient time was not available to undertake the additional evaluations. Since one important assumption, that of the tax laws and depletion allowance remaining unchanged, has recently been negated, additional runs of the *PIR* model are needed to evaluate the effect of this change. Given the flexible modelling format of the *PIR*, evaluation of change in the depletion laws could be undertaken by recalculating the supply model for oil and gas so that the *PIR* model does not fall behind current policy making.

The most important scenario of the *PIR* is the "Business As Usual" (BAU) case in which the U.S. economy is assumed to adjust to a given world price for foreign crude and petroleum products. The key policy assumption made in the BAU case is deregulation of crude oil prices and phased deregulation of natural gas prices. Nowhere does the *PIR* analyze the implications of continuing current regulatory policy of a two tier system in which only "new" gas and "new" oil are deregulated. The price of old oil is currently set at $5.25 per barrel with the average price of crude about $8.25 (in 1973 dollars).[1/] This price is well below the world

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[1/] I will use 1973 dollars throughout this paper.

oil price to which it would rise under the deregulation assumption. Other scenarios considered by the PIR are an accelerated development case with greater offshore leasing and development of energy supply sources and conservation and demand management scenarios in which initiatives are designed to encourage fuel conservation and to force the substitution of coal and electricity for petroleum. Since the PIR concentrates on the BAU scenario, I shall neglect the other cases in which the policy assumptions are very unlikely to be satisfied.

A second key assumption of the PIR is that the world oil price is set exogenously and that sufficient supplies are forthcoming at the world price to satisfy U.S. import demand. Three oil prices are considered, $4, $7, and $11 per barrel, together with the assumption that imported Canadian gas is available at $1.20 per thousand cubic feet (mcf) and liquified natural gas is available at $2.00 per mcf. Since the FEA assumes that the world oil price will approach smoothly one of the three prices and remain there, the possibility of oscillations in world oil price is not evaluated. Furthermore, no analysis is undertaken of the possible effects (if any) of U.S. demand and supply on the world oil situation. Given the great uncertainties surrounding the international oil situation, the FEA assumptions are the natural ones to make. However, an unstable world oil price could have a significant effect on investment decisions whose profitability directly depends on the domestic price of energy.

The last key assumption of the PIR can be characterized as the "absence of constraints" in developing and using domestic sources of energy. For instance, the PIR assumes that sufficient capital is available and forthcoming to finance the costly development of the electic power sector and that stack gas scrubbers are available to permit the burning of coal to generate electricity. While the FEA realizes the importance of these assumptions and even attempts to evaluate their size (e.g., capital requirements for electric utilities are estimated on pp. 283-288), no attempt is made to forecast the likely effects of continuation of the current situation in which public utilities are cancelling planned expansions due to difficulty in raising sufficient amounts of capital.

Thus while the FEA policy assumptions are reasonable, no feel for the stakes involved in the current policy debates over matters like removal of price controls can be gained because the PIR does not give forecasts under alternative policy assumptions. This narrow concentration on one set of policy assumptions is so serious that it should be remedied at the earliest possible time so that the current pressing policy decisions can be evaluated under the consistent analytical framework which the PIR provides.

Overall Framework:

A very important element of a successful energy model is the integration of energy related sectors with a macroeconomic model to evaluate the interaction of differing energy prices with economic growth and prices and wages in the economy. Existing large macroeconometric models are unsuited to the task due to their high degree of aggregation and concentration on problems of effective demand. Production technology in these macro models is based on a constant returns assumption, and while this assumption is suitable for processing of energy for final demand it cannot answer the important questions which arise from the extractive nature of primary energy production characterized by increasing marginal costs of production.

The approach taken by the PIR is to set exogenously the growth of real GNP identically at 3.6% per year in the $4, $7 and $11 per barrel oil case and using this figure calculate the growth in macroeconomic factors using the Data Resources Long Term Growth Model [1, pp. 65 ff.]. Forecasts of macroeconomic data from the Growth Model like inflation (5.9% per year), housing starts (1.4 million units), and the real wage (1.5% per year) are then used as exogenous variables in forecasting energy demand. Nowhere in the PIR model is the effect of different energy prices integrated with the basic macroeconomic model. Thus the interaction between the energy sector and the macroeconomic variables is not captured and a whole range of key questions cannot be answered.

Although the FEA does not integrate the energy model and the macroeconomic model, it does try to assess ex post the effects of the $7 and $11 per barrel BAU situation on the important macroeconomic aggregates given the equilibrium solution of the integrating model (See diagram 1.1.). Using a model of Chase Econometric Associates it forecasts the following rates of growth over the period 1973-1985 [1, pp. 320 ff.].[1]

Annual Rates of Growth of Aggregate Factors, 1973-1985

	$7 BAU Case	$11 BAU Case
GNP	3.7%	3.2%
Personal Consumption	3.4%	3.2%
Gross Domestic Investment	4.9%	3.1%
Employment	1.5%	1.5%
Consumer Price Index	7.1%	7.4%
Real Wage	1.5%	1.5%

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[1] These rates of growth are inconsistent with the macroeconomic variable inputs to the energy model due to lack of integrating the two models. In both the $7 and $11 case the macroeconomic assumptions are based on GNP growth of 3.5% per year, yet the results point to 3.7% or 3.2% growth in the two cases. Likewise, inflation is assumed to be 5.9% per year, but the macroeconomic forecasts are 7.1% and 7.4% per year.

Thus the FEA finds that total output of the U.S. economy is not greatly affected by high energy prices so that the economy can continue to grow even with substantially more costly energy than historically has been used. One error does seem to be present. The real wage is forecast to increase at 1.5% regardless of a $7 or $11 oil price. However, a redistribution of real income would be expected away from U.S. consumers toward the nations which export oil since the price and economic rent on oil has increased greatly relative to other goods. While the FEA results agree closely with the Hudson and Jorgenson [8] forecasts of little effect of higher energy prices that model also lacks an integrated model of energy use into a macroeconomic model. Thus before attaching much confidence to these findings, an expanded model needs to be constructed which has the necessary integration to fully assess the interaction of primary materials prices and economic growth.[1/]

Given the exogenous macroeconomic forecasts, a dynamic demand model is constructed to forecast demand for primary and derived energy products in three sectors of the economy, the household and commercial sector, the industrial sector and the transportation sector. A three step demand estimation procedure is used. First total energy demand in each sector is estimated

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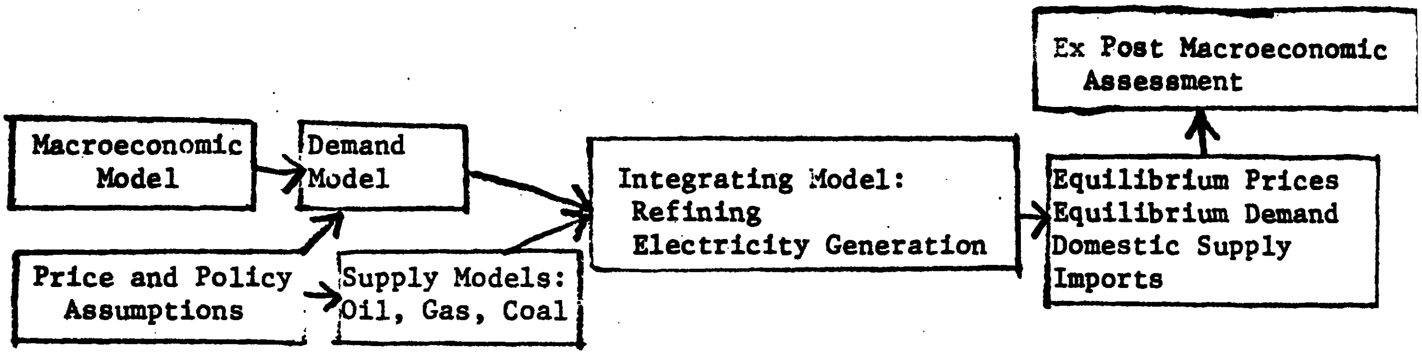
[1/] The PIR also attempts to assess the economic effects of the 1973-1974 embargo [1, pp. 283 ff.] but the evaluation has two fundamental flaws. First the price and quantity effects of the embargo are not effectively separated so that it appears that quantity shortages may have had a significant effect, while in reality price effects which accompanied the embargo are the important factor. Since gasoline, distillate, and residual rose in price by 37%, 61% and 127%, respectively, even very low price elasticities point to the price effects outweighing the quantity effects of the embargo. Second, when evaluating the macroeconomic effects all of the economic downturn of the recession is attributed to the embargo. Yet the U.S. was undergoing the "old time religion" of contractionary monetary and fiscal policies to cure the inflation only part of which was due to the oil price increase. Thus a large upward biased estimate of the cost of the embargo is given.

using the exogenous macroeconomic aggregates and assumed energy prices. Then electricity demand is forecast using the aggregate forecast and the assumed electricity price. After subtracting off electricity demand, the remaining demand for the different fossil fuels is estimated using a set of fuel share equations. The PIR demand model is evaluated in Section 2 of the paper.

Supply estimates of domestic oil and natural gas along with coal are discussed in Section 3. Here instead of using econometric models, interpretative models are used in which "target rates" of drilling in districts are set exogenously to the assumed prices, and the actual drilling undertaken depends on the economic viability of the entire district. While econometric models have had a notable lack of success in forecasting oil and gas production, the approach taken by the PIR seems seriously deficient. Factors such as the target drilling rates and recovery rates which should be endogenous to the decision making process (and dependent especially on prices) are taken as exogenous and thus the results are sensitive to and biased on account of these exogenous assumptions. Thus while the FEA is to be commended in attempting to model the extractive and depletable nature of primary energy production, the discussion in Section 2 indicates that their model is seriously flawed.

Given estimates of demand and supply, equilibrium of the model is found using the outstanding innovation of the PIR, the integrating model. The integrating model, which is a linear programming model, takes the demand estimates and elasticities over the 8 demand regions and the supply schedules and resource requirements over the 12 supply regions and calculates an energy market equilibrium. Schematically, the PIR model may be represented:

Diagram 1.1. Overall Model Structure



The output of the linear program, equilibrium prices, demand, and supply, are all given on a regional level of disaggregation since the integrating model solves the least cost linear program of supplying the given regional demands of energy at minimum total cost of production, distribution, and transportation. In order to use a linear programming model a constant elasticity assumption is made for the regional demand curves and the supply curves are approximated as step functions. These linear approximations do not seem to create serious distortions. The integrating model has a potential advantage over econometric models in a situation which prices are assumed to change markedly. By their very nature econometric models are unlikely to predict well where there are no previous observations. Realizing that in the 1985 forecasts the oil price is assumed to triple or quintuple over recent historical experience, the integrating model forecasts by solving the optimization problem that the market presumably solves under deregulation and competitive assumptions. The procedure used in the integrating model is described in more detail in Section 3. I feel that the approach taken using the integrating model provides a valuable alternative procedure to the usual econometric approach.[1/] While it certainly depends on econometric

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[1/] The drawback in such a linear programming approach is the difficulty of capturing in the constraints the institutions that prevent optimization. However, the FEA assumes in large part an absence of constraints. Furthermore, it is very difficult to capture changing institutions over a ten year period in an econometric model.

estimates of demand, the use of an optimization model rather than a very long extrapolation of econometric estimates is a new procedure in energy models. Further work will determine its usefulness; however, it does represent a significant innovation in the PIR.

My two major criticisms of the overall PIR approach are the failure to assess the importance of the key policy assumptions made and the failure to integrate the energy model into the macroeconomic model. Referring back to Diagram 1.1, the price and policy assumptions should affect the macroeconomic model and the output of the integrating model should be fed back into the macroeconomic model and the whole process iterated until a full equilibrium is found. (For the best of all worlds the output of the integrating model also affects policy decisions, but models of the political process at the policy level await another day.) The PIR has created a viable framework in which to model the demand and supply for energy taking into account the unique aspects of the energy sector, but has failed to connect these models to a macro model. Thus many important long range questions cannot be properly answered until such an integration is achieved.

2. Domestic Energy Supply

Separate models of domestic supply of oil, natural gas, and coal are used in the *PIR*. Each model is the product of a separate task force whose reports are given in detail in separate volumes [2, 3, 4, 5]. The models forecast supply over the period 1973-1985 by using an extrapolation of recent past experience under a range of assumptions on the price of imported oil and domestic gas and coal prices. The models for oil and gas are very similar, both being extensions of an earlier modeling approach taken by the National Petroleum Council [11]. The coal supply model takes a similar approach but due to considerably less uncertainty about reserves of coal, it is more satisfactory than the oil and gas models. The last major source of domestic energy supply, nuclear power, is considered along with the production of electric power. The *PIR* forecasts an increasingly important role for electricity due to its excellent substitution possibilities, both in production and use. However, potential problems exist for increasing use of electricity, and these problems are discussed in the concluding part of this section.

Oil Supply [1]

The oil supply model used by the PIR is basically an updating and extension of a model developed by the National Petroleum Council (NPC) in its study, U.S. Energy Outlook [11]. The NPC model is not explicitly based on supply as a function of oil price but rather is an extrapolation over the period 1971-1985 of recent experience under four different scenarios. The four different scenarios range from an optimistic case of exploratory well drilling increasing by 7.5% per year with a relatively high discovery rate down to a pessimistic case of exploratory drilling decreasing by 3% per year with discovery rates less than 2/3 that of the optimistic case. Under these assumptions domestic oil production in 1985 is forecast to range from 15.5 million barrels per day (m.b.d.) for the optimistic case down to 10.4 million barrels per day in the pessimistic case.

Only after making the nonprice forecasts did the NPC calculate the required price of oil which would cover costs in the four cases and return 15% on net fixed assets. The required price is the average required price for all oil production in the United States and varies for 1985 from $8.23 (in 1973 dollars) for the optimistic case down to $6.50 for the pessimistic case. Under the assumption of a continuation of a two-tier pricing system the required price for new oil in 1985 varies from $10.51 per barrel to produce 15.5 m.b.d. down to $9.09 to produce 10.4 m.b.d. Thus the NPC model does not have a supply curve where marginal decisions are made as a function of price, but rather reverses causality and answers the question, "what price is needed to cover average costs (exclusive of rents) given a

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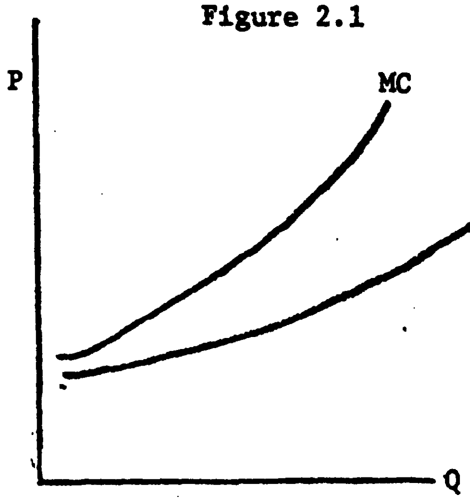
[1] Much of the analysis on oil supply and gas supply in the next two sections has benefited from conversations with Paul MacAvoy and his analysis in the M.I.T. report [15].

certain level of supply". Given an upward sloping (true) marginal cost curve so that marginal cost exceeds average cost, the NPC quantity-price relationship lies uniformly to the right of the marginal cost curve as shown in Figure 2.1. Thus as the NPC correctly notes, their four scenarios with associated average price changes should not be interpreted as a supply curve with elasticities. For a given equilibrium price which producers would take as the marginal return, incorrect use of the NPC forecasts would predict too much oil being produced and price-elasticities of supply downward biased. The NPC study, while providing useful information about possible results as a function of exploratory drilling, cannot be used a supply relationship in construction of an equilibrium energy model.

Figure 2.1



1985 Oil Supply

The FEA Oil Task force modifies the NPC procedure in attempting to develop a conceptually correct oil supply curve. Since the world oil price is taken as exogenously set by OPEC, total domestic production is forecast under three constant price paths over the period 1974-1985. In the Business as Usual Case [1] the FEA forecasts are

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[1] An Accelerated Development case of accelerated Outer Continental Shelf leasing and use of Naval Petroleum Reserve No. 4 is also considered with supply being about 25% higher.

FEA Oil Supply Forecasts, BAU

	Million Barrels Per Day			
Price (1973 dollars)	1974	1977	1980	1985
$ 4	10.5	8.9	9.5	9.0
7	10.5	9.5	11.0	11.6
11	10.5	9.9	12.2	15.0

The Task Force report emphasizes the uncertainty of the forecasts stating that within the range of reasonable assumptions of each of 10 factors used in the forecasts, e.g., size-frequency distribution of undiscovered reserves, drilling costs, or tax rates, the forecasts could vary from 10% to 40% in 1985. Few other econometric estimates of oil supply exist to compare the FEA forecasts with. Houthakker [13] gives estimates at $4, $7, and $10 per barrel which exceed the FEA forecasts by over 25% with 15.1 m.b.d. at $7 in 1985. MacAvoy and Pindyck [9] forecast 10.6 m.b.d. at $7 in 1980 which is less than the FEA by 3.7%. Almost all other forecasts are judgemental, often predicting oil production in a given year without stating the price of oil that the forecast is based on. For similar reasons as the NPC forecast using average costs rather than marginal costs, the FEA forecasts are likely to have a downward biased price elasticity. However, the forecast of quantity given the world oil price is very close to the mean value of the judgemental forecasts. This fact must be interpreted gingerly since the NPC forecasts appeared first, and judgemental forecasters are prone not to stray far from the established standard. But in the absence of further econometric work, the FEA predictions at $7 or $11 represent the consensus viewpoint. While even a 50% confidence interval might be as wide as 2 m.b.d., no large systematic bias enters the FEA analysis which would lead to a change in the mean forecast or an asymmetric confidence interval. However, severe conceptual problems exist in the FEA supply model, which lead to downward biased price elasticities at both low and high oil prices and to downward biased primary supply estimates at high oil prices. These problems will now be discussed so that future econometric work may benefit from the shortcomings of the FEA approach.

The FEA supply model divides the U.S. into 12 producing regions with the North Slope of Alaska being treated separately. In an approach similar to that of the NPC model, targets for exploratory drilling in each year from 1974-1988 are chosen, independent of any price considerations. For example, Region 2 which comprises Washington, Oregon, and California (excluding the Pacific Ocean) has the following drilling targets specified

Table 2.1. Target Exploratory Footage, Region 2

(Thousands of Feet)

1974	653	1982	1634
1975	967	1983	1749
1976	1054	1984	1871
1977	1144	1985	1983
1978	1235	1986	2102
1979	1328	1987	2229
1980	1422	1988	2351
1981	1527	TOTAL	23,249

The target exploratory footage presumably is an extrapolation of recent past experience and represents a judgemental estimate of maximum drilling rates for oil given an $11 per barrel price. Also taken as given is the average discovery rate of oil per foot drilled for the complete region for the exploratory drilling undertaken. The amount of development drilling is a downward sloping function of the amount of exploratory drilling (due to a falling discovery rate), but it too is assumed to have a success ratio which is constant across the region and independent of price. The total amount of oil found as a function of total exploration is a downward sloping function estimated from recent historical experience. Marginal calculations presumably enter here since the better prospects will be explored first with decreasing marginal gains as poorer prospects are explored. Lastly, secondary and tertiary recovery as well as primary production are specified as constant fractions across the complete region independent of price. Likewise the amount of associated natural gas produced is a constant fraction of oil production for each region, independent of natural gas price.

The pattern of potential production at the regional level is therefore completely specified independent of the price of the products. To determine when and if the regional drilling project is undertaken, a discounted cash flow calculation is made to determine the economic viability of the project. The initial costs involved are geological exploration, costs of drilling, platforms, and equipment, and overhead. Expensed items and tax credits are subtracted from these initial costs to get the initial year expenses, C_o.[1/] Revenues begin in year one. Gross revenue is determined by multiplying production of oil and natural gas by their assumed prices with net revenue determined after subtraction of royalty payments and taxes. Yearly costs once production begins include well operating costs, gas plant

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[1/] Costs of lease acquisitions and lease rentals are excluded from cash flow calculations since they represent economic rents which should not influence the drilling decision.

operating costs, secondary and tertiary production costs, and overhead.[1] The net present value (NPV) of drilling in the region then follows using a discount rate r of 10% per year

$$NPV = C_o + \sum_{t=1}^{T} (NR_t - C_t)\, e^{-rt}$$

The lifetime, T, of the project is set constant for all regions independent of prices and yearly production is assumed to decline exponentially also independent of prices.

To determine the quantity supplied as a function of the exogenous oil price, the present value calculation is made for each assumed price. Cumulative exploratory drilling actually undertaken is calculated by assessing the economic viability of each year of target exploratory footage given in Table 2.1. For Region 2, cumulative exploratory drilling over the period 1974-1988 is

Region 2, Cumulative Exploratory Drilling, 1974-1988 (Thousand Feet)

$7	0	$11	12,712
$8	653	$12	12,712
$9	5053	$13	16,566
$10	5053	$14	23,329

Comparing cumulative exploratory drilling with target exploratory footage, their relationship becomes clear. For $7 oil no drilling is done in Region 2 because the NPV is negative, but when the oil price rises to $8 the target drilling for 1974 is undertaken because the NPV becomes positive at the

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[1] All costs, taxes, royalties, and the discount rate are assumed constant over the period in each region except for secondary and tertiary recovery production costs which follow a linear trend.

higher price. When the price rises to $9, drilling up through 1978 takes place, but not until the oil price rises to $14 is all target drilling found to be economically viable. The reason that drilling in later years does not take place until the price rises is, first, that the amount of oil found is assumed to be a downward sloping function of cumulative drilling, and second, drilling costs are assumed to be an upward sloping function of cumulative drilling and finally, secondary and tertiary production costs go up as a linear function of time. For example in Region 2 when the price rises from $7 to $11 cumulative drilling increases by about 12 million feet. But oil found per exploratory foot drilled falls from about 125 to 95 while costs for production wells rise from $37.70 per foot to $42.28 per foot. Thus the extra, less profitable, drilling does not take place until the price rises sufficiently to cover the greater drilling cost and expected lower proportion of oil found.

As the price reaches $9 all exploratory drilling is undertaken in Regions 1, 6, 8, 9, 10, and 11A. When the price rises to $11 no more drilling or production is undertaken in those six regions. Yet when the price rises the oil companies are expected to undertake even more exploratory drilling in a region because even though the success ratio falls, all oil found will yield a higher price. Furthermore, when the price rises the number of wells drilled in a given year would also rise. In Region 2 whether the price is $8 or $15 the FEA forecasts 653,000 feet drilled in 1974. But profit maximization should cause drilling to expand until the expected marginal return equals the marginal cost of the last well drilled. It is a mistake to exogenously set a certain footage and not increase it when it is all found to be economically profitable. When the price rises from $8 to $15 the only effect in the model is to increase supply in later years after 1978. Yet recent activity in the domestic petroleum industry shows oil well drilling in 1974 is 30% higher than 1973, an expected result since the price of new oil has doubled [12].

The reason all this is important is the effect it has on two fundamental concepts: price elasticities will be downward biased and the timing of the supply response to higher prices is incorrect since in the earlier years drilling is constrained to be almost unaffected by higher prices. The Task Force makes the mistake of trying to use the NPC model and to adapt it as a supply function neglecting the fact that optimization decisions are made at the margin with factors such as drilling footage endogenously determined by expected prices. Thus at low oil prices the FEA supply function will tend to overestimate the amount of oil produced while at high prices supply will be underestimated.

The FEA commits a fundamental aggregation error in applying an investment appraisal technique designed for an individual (marginal) investment and applying it on a regional (average) scale with exogenously set regional drilling targets independent of oil price. At low prices only individually profitable projects will be undertaken so using average cost leads to an upward bias. When price becomes high, companies will not stop drilling when they reach the limits of a price independent exploratory footage target but will continue exploring until expected net marginal revenue equals marginal cost. Also, companies will drill more intensively in existing fields just as old mines are reopened when metal's prices increase. Thus a downward bias is introduced at high oil prices and the price elasticity is downward biased at both low and high prices. Aggregation of marginal cost decisions into average cost decisions and taking as exogenous factors which are endogenous to the decision making process makes the methodology employed by the Blueprint extremely suspect. However, given the great uncertainty surrounding secondary and tertiary recovery which have been rarely used to the present, the final bias of the FEA forecasts is indeterminate. Price elasticity is almost certainly too low and primary supply at high prices may well be too low, but better supply forecasts await improved econometric models which correctly model the relevant economic decisions.

Natural Gas

Production of natural gas derives from two sources. The first source, dissolved natural gas associated with oil production, is essentially a joint product. Supply of associated natural gas should therefore be sensitive to both the price of oil and the price of gas. The second source is nonassociated natural gas production. Supply of nonassociated gas is mainly sensitive to the natural gas price although the distinction is not quite so clear cut since producers are never sure what will be discovered by drilling. The methodology used by the Natural Gas Task Force is very similar to that used in forecasting oil production. Associated natural gas production is taken directly from oil production by assuming a linear trend relationship between oil well drilling and associated gas discoveries. Nonassociated natural gas production is forecast using an essentially identical model to the oil model - an update of the NPC model used in U.S. Energy Outlook [11] with the addition of a discounted cash flow evaluation scheme to calculate the economic viability of the projects.

As the following table indicates, associated natural gas production is forecast to be relatively sensitive to the exogenously given oil price. For instance, associated production increases by 22% in 1985 when the oil price increases from $7 to $11 for an implied price elasticity of .49.

Associated Dissolved Natural Gas Production [1]

(Trillion Cubic Feet per Year)

Oil Price $ Barrel	1974	1977	1980	1985
4.00	3.7	3.3	3.8	5.2
7.00	3.7	3.5	4.4	6.4
11.00	3.7	3.5	4.6	8.0

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[1] Gas price is assumed to be $0.89 per MCF in calculating the economic viability of oil exploration projects.

The forecasts here are subject to the same basic criticisms as those of the oil forecasts, exogenously set target drilling footage and confusion of average and marginal cost, since they come from the same model. One additional point should be noted. In assessing the economic viability of oil projects, gas price is assumed to be $0.89 per thousand cubic feet (MCF) thus ignoring the joint product character of oil and associated natural gas production. As the oil price rises, under the deregulation assumptions of the PIR, natural gas price should also rise since it is a close substitute in many uses for oil.[1] It is difficult to assess the sensitivity of oil exploration to natural gas price but a downward bias in associated natural gas production is evident. The magnitude of the bias can only be determined with an econometric model designed to recognize the joint product relationship [9].

The model used to forecast nonassociated natural gas production is an updated NPC model that uses present value calculations to assess economic viability. Projected drilling rates are taken as exogenous to prices, and the "high" drilling rate of 5% increase per year of the NPC model is used "since this schedule was felt to be representative of the drilling rates that could be attained under a continuation of the present natural gas regulatory environment" [5, p. III-6].[2] A discount rate of 10% is used and all projects are assumed 30 years in length. The weakness of the model is the same as the oil model - the U.S. is divided into 12 regions with drilling being undertaken only if expected net revenues exceed <u>average</u>

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[1] The regulated price of natural gas has recently been about $0.70 per mcf. The equilibrium price should well exceed $0.89 per mcf when oil is $11 per barrel since the PIR states that the price is "allowed to rise to clear the market" [1, p. 91].

[2] Note the apparent inconsistency of this assumption with the price clearing partial regulation assumption.

cost for the entire region with no increase in drilling in a given year once the target drilling footage has been met no matter how much the price increases. While in the oil forecasts the direction of bias could not be determined, here a clear downward bias in nonassociated production is evident. The FEA forecast of nonassociated natural gas production is almost independent of the market clearing price. For example, in all years when gas price goes up by 120% from its approximate current price, nonassociated production does not rise at all!

Nonassociated Natural Gas Production

(Trillion Cubic Feet per Year)

$/MCF	1974	1977	1980	1985
$ .40	16.5	15.2	13.3	9.5
.60	16.7	15.8	16.0	16.7
.80	16.7	16.1	16.4	18.1
1.00	16.7	16.1	16.4	18.2
2.00	16.7	16.1	16.4	18.2

Thus the FEA assumes nonassociated production to be totally price inelastic in the relevant range due to the use of the target drilling series assumed to increase at only 5% per year. The only increase in gas supply comes from associated natural gas production as the oil price rises and from imports which are assumed available at $1.20 per mcf. These forecasts seem severely downward biased especially given the recent surge in gas exploration coupled with the partial deregulation assumption of the PIR.

The effect of this bias is considerable since natural gas currently provides 1/3 of total energy consumption and 1/2 of total nontransportation energy consumption. Furthermore, given the substitution possibilities between natural gas and oil in many uses, a price of $0.90 per mcf given $7 oil and $1.40 per mcf given $11 oil would be first round guesses at the equilibrium natural gas price given exogenously set oil prices so that more associated production would be expected. This downward bias for supply coupled with incorrect estimation of demand for natural gas discussed in a later section leads to the conclusion that the PIR overestimates the U.S. demand for imported oil especially in the $11 case. Natural gas supply cannot be as inelastic as the FEA forecasts it to be.

The reasons for this incorrect forecast is that completely <u>independent</u> of price the Task Force assumes drilling to increase at 5% per year (although the average increase in the last two years is around 25%) and that the recent sharp increases in drilling costs will continue over the next ten years [12]. Furthermore, estimates of the recovery rate of gas as a function of cumulative drilling decline much faster than the assumed recovery rate of oil. An implicit, incorrect assumption is made that deregulation will have no effect on gas supply. Thus a severe downward bias is introduced into the forecast because the Task Force based drilling rates on the experience of the early 1970's when gas drilling was dampened by the efforts of field price regulation and a rapid increase in drilling costs.

While the direction of the bias is downward, an assessment of the magnitude is difficult. With $11 oil the PIR forecasts 21 trillion cubic feet in 1980 and 26.2 trillion cubic feet in 1985. Converting to quadrillion BTU's per year leads to estimates of 21.6 quads and 27.0 quads, respectively. These estimates are well below the NPC forecasts [11] in the high case of 31.3 and 41.1 quads and the Ford Foundation Base Case [7] of 28.0 and 32.0 quads. For oil at $7 per barrel in 1980, MacAvoy and Pindyck [9, Ch. 5] forecast 36.1 quads. Concentrating on $11 oil for 1985, the FEA forecast is between 5 and 14 quads below alternative estimates. This downward bias amounts to between 2.4 and 6.7 million barrels per day of oil equivalent - enough to make the U.S. self-sufficient in energy in 1985 with $11 oil given FEA demand forecasts and substitution of natural gas for oil. A similar calculation shows that at $7 per barrel oil, the FEA's forecasts of 12.4 million barrels per day of oil imports could be halved by replacing oil use with the likely additional gas supplies. Therefore, a significant and important bias is present in the PIR's natural gas supply forecasts. This bias could easily make the difference between the U.S. being a net energy <u>exporter</u> rather than importer in the $7-$11 range for oil prices in 1985.

The models constructed to forecast both oil and gas supplies are based on incorrect economic methodology. The most important factors are taken to be exogenous and are based more on an extrapolation of recent past experience than on economic decisions. As in the natural gas model, a certain growth rate of drilling is specified exogenously and only ex post is it determined if the drilling is economically profitable. Yet when the natural gas price doubles from the recent price, all the targeted drilling is undertaken and so no matter how much more the price rises, no further supply response is forecast. Supply models based on economic decisions where variables such as exploratory drilling become endogenous seem necessary to avoid the errors inherent in the FEA methodology. Since the greatest uncertainty in energy models is with the supply forecasts, it is critical that further work be done in this area.

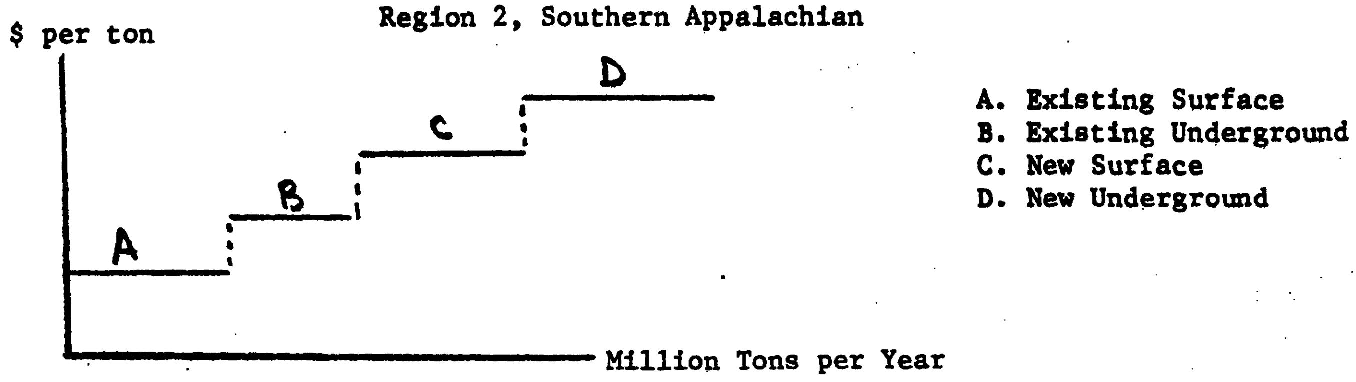
Coal

The approach used by the coal Task Force is similar to that used in estimating the supply functions of oil and gas. The U.S. is divided into 7 regions and in each region for each year from 1974-1990 production targets are set. These production targets are met by a combination of mining from existing and new deep mines and surface mines. The relative amounts of coal from each type of mine are not decided by a cost minimizing (marginal) approach but rather from "professional judgement used to determine a logical mix of mines for each region for each year" [4, p. 20]. A "minimum acceptable selling price" which is an average cost concept is then developed for each region. But since this price is determined separately for each type of mine, problems of aggregation are not as severe as in the oil estimates.

The minimum acceptable selling price is determined using detailed engineering cost estimates. A 15% rate of return and 20 year life of project assumption is coupled with the assumption of no increases in factor costs at 1973 prices to determine costs for each mine type. The cost for each of the four mine types then given the steps of the regional supply curve

Figure 2.2

Region 2, Southern Appalachian



The highest price coal is new underground coal which entails opening new mines. The supply curve here is assumed perfectly elastic since the Task Force assumes that scarcity of deep mine reserves is not a constraint. Even though the new deep mines are more expensive, the Task Force assumes they will not be replaced by new surface mines since deep-mined coal generally has a higher BTU content and lower sulphur content. Furthermore, in both the $7 and $11 oil cases, all but one of the seven regions have equilibrium supply on this perfectly elastic section of the supply curve with marginal cost (in Appalachia) of $13.50 per ton. This finding is a result of the Task Force's assumption that "in the long run coal supply will be demand constrained instead of being either resource or price constrained." [4, p. 31].

The supply function given in Figure 2.2 is the same for all years in each region. This constant supply curve result follows from two key assumptions: no increase in factor costs over the period 1974-1985 - which would tend to shift the curve upward - and no effect from depletion. As a result for any region and mine type the new mine prices are constant over time. The Task Force explicitly states these assumptions, but makes no estimates of what effect their nonfulfillment might have. An inconsistency in their assumptions is present since they assume that current manpower shortages are alleviated by increases in workers wages and benefits [4, p. 17], an occurrence which is unlikely without an increase in real wages which will increase factor costs unless productivity increases sufficiently fast to counteract rising wages. Since wages constitute 35% of total costs of mining, this assumption could be seriously violated if the United Mine Workers decide to press for higher wages. The effect of assuming negligible depletion is more difficult to assess; but the effect of the two assumptions probably leads to a downward bias in expected coal costs over the next decade.

Other important assumptions by the Task Force are the existence of stack gas scrubbers in later years and an adequate transportation network for shipment of western coal to eastern markets so that the "clean fuels" deficit is eliminated. While neither of these assumptions is objectionable, both should lead to higher costs of coal than the PIR forecasts. These higher costs could have a significant effect since the PIR forecasts that in the $11 case in 1985 coal will increase its share of energy supply from the current 17% to 23.4%. Most of this increase in coal consumption occurs in the electric utility sector and would lead to higher electricity prices than the FEA forecasts. However, given current judgement the downward bias in the cost of coal is probably not large enough to have a significant effect on the supply of electricity forecast in 1985.

While the forecasts of the coal supply model seem "reasonable", logical problems still exist due to the assumption of no depletion effects. The Task Force assumes a given mix of mines based on their professional judgement, but the mix is not determined endogenously in the model as it should be on cost minimization criteria. If depletion effects are added to the model, the mix would change and the perfect elasticity assumption of the coal model is no longer reasonable. An explicitly specified model seems preferable so that the effects of altering the assumptions can be evaluated.

Electricity and Nuclear Power

The PIR forecasts a greatly increased role for electricity in satisfying U.S. energy needs by 1985. While total energy use is forecast to grow at 2.7% over the period 1973-1985 for the $11 oil BAU case, electricity supply is forecast to grow at the higher rate of 6.3% per year. The reason for this dramatic change in energy use is the substitution possibility for electricity, both in production and use. Electricity can be produced by both fossil fuels and by hydropower and nuclear power. Relatively plentiful and inexpensive coal can be substituted for higher cost imported oil, thus helping reduce reliance on imported oil. Furthermore, electricity is a substitute for fossil fuels in many energy uses. In applications where stationary heat is required, electricity can be substituted for oil produced heat again providing an economic alternative free from oil import problems. Lastly, in the period up to and beyond 1985, electricity is the vehicle for using nuclear power which many believe offers a partial solution to long range energy supply problems.

The FEA electricity supply model is an excellent example of the use of an engineering production function rather than the more commonly used econometric estimates. Assuming as constant over 1973-1985 the historic ratios of capacity factors, reserve requirements, and load requirements, the electricity model meets the demand with the least cost combination of existing and incremental plant capacity.[1/] The amount of nuclear capacity in each year is taken as exogenous (and the same in all BAU runs).[2/]

[1/] The load factors used are 75% base load, 20% intermediate load, and 5% peak load capacity.

[2/] For new base load capacity nuclear power is the least expensive alternative. However, the PIR constrains the amount of new nuclear capacity because of long lead times, now about 10 years, in construction of nuclear generating plants.

Thus given fuel costs, equipment design characteristics and costs, and the cost of capital, the program is solved which meets electricity demand at least cost. A weakness of this approach is the use of historic ratios, especially the load factors, as exogenous rather than solving for them endogenously as part of the optimizing solution. This fact becomes especially important given the radical change in relative fuel prices over the past few years and the increasing importance of coal and nuclear generated electricity. The overall approach adopted by the FEA is sound; the exogeneity of the historic ratios could easily be eliminated in an expanded model.

The least cost solution for new base load plants most heavily weights the variable costs, fuel costs and operating costs, so that the PIR forecasts most new base load plants will be either nuclear plants or coal fired steam turbine plants. On the other hand, intermediate and peaking plants trade off higher variable costs against lower capital costs since they are not in continuous use. The least cost solution for the 1985 $11 oil BAU case is

Load Type	% of Total	Capital Costs (per kilowatt)	Generation Costs (per kilowatt hour)
Base	75%	$350-480	$.0014-.0022
Intermediate	20%	$210-240	$.0025
Peak	5%	$100-120	$.0040-.0050

Since base load represents 75% of total capacity, the PIR forecasts increased use of coal in electricity generation. This forecast is a reversal of the historic trend which has seen coal fall from 65% of total fuel consumed for generation in 1965 to 54% in 1973 while oil doubled from

10% in 1965 to 20% in 1973. This marked shift is evident in the electricity capacity forecasts for 1985 $11 oil in the BAU case:

Eletricity Capacity and Fuel Consumption

KW×10^6 (GWe)

	1973 Capacity [1]		1985 Capacity		1985 Fuel Consumption (Trillion BTU's)	
Total	424		922		34397	
Coal	167	(39.4%)	327	(35.4%)	16424	(47.7%)
Nuclear	20	(4.7%)	204	(22.1%)	12509	(36.4%)
Oil	78	(18.4%)	81	(8.8%)	2954	(8.6%)
Gas	61	(14.4%)	48	(5.2%)	2510	(7.3%)

Gas turbines, used largely for peak load plants, decrease while oil fired turbines, used largely on the Eastern seaboard, remain constant.[2] Coal capacity grows at approximately the average capacity growth rate, while nuclear generating capacity increases to over 1/5 total capacity.

The forecast of greatly increasing nuclear generation capacity must be regarded as highly uncertain. Since the construction lead time is presently about 10 years with long delays in equipment delivery and construction as well as difficulty in obtaining licenses, any difficulties in the near future could lead to a large reduction in electricity capacity.[3] Also nuclear plants (and coal) have the highest capital costs and the present difficulty of utilities in raising capital to finance expansion

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[1] Total includes hydro generation capacity and combustion turbines.

[2] The electricity model is constrained not to install gas fired generating capacity even though it has lower cost for peaking plants.

[3] A curious inconsistency is present since although electricity capacity is forecast to grow at 6.3% per year, while electricity demand grows at only 5.6% per year.

may lead to further delay and upward biased forecasts. Thus while the PIR explicitly assumes that financing will not be a constraint, this current problem and the other difficulties associated with developing nuclear capacity may make the FEA forecasts much too optimistic.[1] Unless present constraints to developing new electricity capacity are eased soon, the PIR forecast of a greatly increased role of electricity in meeting energy demand will be impossible to attain given the very long lead times required to construct electricity generating capacity.

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[1] For an analysis of the effect of financing problems on the electric power sector see Joskow and MacAvoy [14].

3. DEMAND ESTIMATES AND INTERACTION WITH THE INTEGRATING MODEL

As described in Section 1, the FEA Demand Simulation Model is used to compute the regional demand estimates and national price elasticities which are inputs to the integrating model. Each solution of the linear program is based on a particular set of regional demands for various fuels which in turn is based on certain assumed energy prices. Subsequent solutions of the overall integrating framework are performed until the system has obtained "equilibrium" in the sense that the prices implicit in the demand figures for a particular solution are consistent with the implicit supply prices of domestic energy sources.

Hence the structure of the demand model (as summarized in the elasticity measures) and the detailed mechanisms of the procedure by which the system iterates to an equilibrium solution are as important to the process of estimating energy production and consumption levels as the supply functions discussed in Section 2.

Methodology of the FEA Demand Simulation Model [1/]

The model developed by the FEA involves first estimating energy demands at the national level, conditional upon macroeconomic and demographic variables, and energy prices, and technology variables, and then disaggregating to the Census region level of detail. Fuel and Power demands are estimated for four major consuming sectors: household and commercial,

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[1/] The FEA Demand Simulation Model is described in PIR [1], Appendix II. Footnote 1 of that appendix indicates that two technical reports will be published describing the model, including reports by Data Resources, Inc., and FEA, but as yet these reports have not been released.

industrial, and transportation. Industrial demands for fossil fuels for use as raw materials are estimated separately.[1]

The transportation demand equations are based upon differing specifications depending upon the particular fuel. For example, gasoline demand per capita is a function of gasoline price and income per capita. Demands for liquified gases and residual fuel oil are functions of prices, but jet fuel demands are independent of price, depending only upon assumptions about route miles and load factors.

The demand equations for the household and commercial and the industrial sectors employ a common specification. The FEA procedure involves a three-step process:

(1) <u>Total energy demand</u> is estimated from aggregate time-series data, using an energy price index (calculated with actual energy shares and prices year to year) and other variables representing economic and industrial activity. For example, in the household and commercial sector the estimated total energy demand equation in trillion BTU's has the log-linear form

$$\log \text{TOTHC} = \alpha_0 + \alpha_1 \log\left(\frac{\text{HF}_{-2}}{\text{TOTHC}_{-2}} \cdot \frac{\text{PHF}_{-1}}{\text{CPI}_{-1}} + \frac{\text{ELEC}_{-2}}{\text{TOTHC}_{-2}} \cdot \frac{\text{PELEC}_{-1}}{\text{CPI}_{-1}}\right) + \alpha_2 \log \text{HOUSE} + \alpha_3 \log \text{YDIS}$$

where HF is the amount in BTU's of heating fuel consumed with PHF its price index and CPI the consumer price index while ELEC and PELEC are the con-

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[1] Raw material demands are assumed to be a function of industrial activity levels, lagged consumption levels, and time. Prices are not included in these equations.

sumption in BTU's and price index, respectively, of electricity. The variable HOUSE is the housing stock and YDIS is disposable income. Thus individual energy demands and prices are aggregated into an index; the individual shares are estimated at the third step of the process.

2. Electricity Demand: In the first step total demand for energy, both fossil fuels and electricity, is estimated. In the second step electricity consumption is estimated and subtracted from total energy consumption in each sector. For example, in the household and commercial sector electricity demand is estimated by the log linear equation

$$\log \text{ELEC} = \log \text{HOUSE} + \alpha_0 + \alpha_1 \log \frac{\text{PELEC}}{\text{CPI}} + \alpha_2 \log \frac{\text{PHF}}{\text{CPI}} + \alpha_3 \log \text{YDIS} + \alpha_4 \text{MDDAY}$$

where the only new variable is MDDAY, mean degree days.[1] Once electricity demand is estimated, it is subtracted from the total energy demand estimate from step one. The remained is the total "direct demand" for fossil fuels by each sector. This total demand for fossil fuel is then divided into its components in the last step.

3. Fossil Fuel Shares: After electricity has been subtracted off, fossil fuel demand is divided into its component shares. For example, in the household and commercial sector six share equations are used to estimate

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[1] While an attempt to use marginal price in the household and commercial sector is made, it appears that average prices are used in the industrial sector. Since average price decreases with demand, a upward bias in the own price elasticity of electricity results. This mistake may explain why the PIR has to later "doctor" the estimated industrial electricity elasticities by dividing them by 6.0.

the shares of seven fuels: anthracite coal, bituminous coal, natural gas, liquified gas, kerosene, residual fuel, and distillate fuel. The last share, for distillate fuel, follows from the adding up criterion that fuel shares must sum to unity. To estimate the shares, a derived demand framework is used with an econometric specification similar to a conditional logit probability model. Each energy share is estimated conditional on its own characteristics (price) and the characteristics of the base fuel, distillate. Thus the ratio of the share of natural gas consumption to distillate fuel consumption in the household and commercial sector is estimated by the equation

$$\log\left(\frac{SNG}{SDIS}\right) = \alpha_0 + \alpha_1 \log\left(\frac{PNG}{PDIS}\right) + \alpha_2 \log(TIME) + \alpha_3 \log\left(\frac{SNG}{SDIS}\right)_{-1} .$$

The ratio of the shares depends only on own price and the price of the basis share together with a time trend and the lagged share ratio. The prices of the other competing fuels do not directly enter the equation.

This econometric specification imposes very strong assumptions on the structure of underlying demands. For instance, the specification imposes the restriction that all cross price elasticities with respect to a given price change are identical. Therefore, the cross-elasticity of anthracite coal and natural gas with respect to residual are assumed to be the same. An improvement in the demand equations would be to include other prices beside only the own price and base fuel price in the specification. Then the cross-elasticities would not be constrained to have identical values.

The results of the three step process are estimates of total national energy demand, national electricity demand, and national energy demand for the principal fossil fuels, coal, natural gas, and petroleum products.

These national estimates are disaggregated down to the level of regional demand functions at a later point for use in the integrating model.

Inputs to the Integrating Model

The national (aggregate) demand system forecasts national demands and own price and cross price elasticities in each of the three sectors. The procedure used is to specify an exogenously given path of energy prices over the period 1974-1985. National demand forecasts and elasticities are estimated for each year on the price path. Forecasts of demands and elasticities are made on the regional level from these national forecasts, and those forecasts provide the basic demand input data to the integrating model which solves the system to find an equilibrium. The procedure used to estimate the regional demand curves is as follows.

National Demand Forecast. A set of prices for different energy sources for the period 1973 to 1985 is specified, based on a terminal (1985) price of crude oil (either \$7, \$11, or \$15 per barrel). The sets of prices used in the PIR analysis are shown in Table 3.1. The prices in the table for oil products, residual fuel, distillate, and gasoline are determined from the crude oil price and by a constant markup assumption. The natural gas and coal prices are set at values exogeneously determined by the analyst. The time path of prices for oil products and electricity between 1973 and the assumed price in 1985 is based on an exponential trajectory, with 90 percent of the 1973 to 1985 price change achieved by 1977, as shown in Table 3.1.

These vectors of energy prices are then used to compute price indices akin to the ones used in the original model estimation. The shares of energy demand do not change over the 1973-85 period in constructing this

Table 3.1*

Prices for $7.00 Crude Scenario
(1973 Dollars)

	1973	1977	1980	1985
Crude Oil ($/Barrel)	4.001	7.001	7.001	7.001
Coal ($/Ton)	10.44	10.44	10.44	10.44
Natural Gas ($/1000 Cu. Ft.)				
Household & Commercial	1.254	1.254	1.254	1.254
Industrial	0.6425	0.6423	0.6423	0.6423
Residual ($/Barrel)	4.581	7.001	7.001	7.001
Distillate ($/Barrel)	5.584	9.491	9.143	8.680
Gasoline ($/Gallon)	0.3971	0.4368	0.4237	0.4063
Electricity (¢/kWh)				
Household & Commercial	1.430	1.430	1.430	1.430
Industrial	1.931	1.930	1.930	1.930

Prices for $11.00 Crude Scenario
(1973 Dollars)

Crude Oil ($/Barrel)	4.001	9.376	10.34	10.86
Coal ($/Ton)	10.44	10.44	10.44	10.44
Natural Gas ($/1000 Cu. Ft.)				
Household & Commercial	1.254	1.254	1.254	1.254
Industrial	0.6425	0.6423	0.6423	0.6423
Residual ($/Barrel)	4.581	9.376	10.34	10.86
Distillate ($/Barrel)	5.584	11.87	12.48	12.53
Gasoline ($/Gallon)	0.3971	0.4933	0.5033	0.4981
Electricity (¢/kWh)				
Household & Commercial	1.430	1.630	1.681	1.708
Industrial	1.931	2.200	2.269	2.306

Prices for $15.00 Crude Scenario
(1973 Dollars)

Crude Oil ($/Barrel)	4.001	11.75	13.68	14.71
Coal ($/Ton)	10.44	10.44	10.44	10.44
Natural Gas ($/1000 Cu. Ft.)				
Household & Commercial	1.254	1.254	1.254	1.254
Industrial	0.6425	0.6423	0.6423	0.6423
Residual ($/Barrel)	4.581	11.75	13.68	14.71
Distillate ($/Barrel)	5.584	14.24	15.82	16.38
Gasoline ($/Gallon)	0.3971	0.5498	0.5827	0.5897
Electricity (¢/kWh)				
Household & Commercial	1.430	1.830	1.932	1.986
Industrial	1.931	2.470	2.608	2.681

*Reproduced from Table AII-9, PIR.

index; 1972 weights are used throughout. Total energy demand for each year is then estimated from step 1 of the national demand system using the total energy demand equations for each sector with values of the independent variables being the composite energy price index and indices of economic activity such as disposable income exogenously forecast by a macroeconomic model. Individual energy product demands are then computed using step 2 to estimate electricity demand and step 3 to estimate individual fossil fuel shares, with the 1973-85 prices for the separate energy products being input as independent variables.

Demand Elasticities. Each own and cross price elasticity then is calculated by changing the price of one fuel at a time by 5 percent and observing the set of quantity changes each year that result. A separate set of these calculations is done under the \$4, \$7, \$11, and \$15 ultimate oil price. For the household and commercial and the industrial sectors, the quantity change which is observed under this procedure is composed of two parts: (1) the change in total energy demand from step 1 which is a function of the composite fuel index derived from the individual energy prices, and (2) a change in the fuel shares through step 3 with the logit fuel split equation. These own price elasticities and cross price elasticities are then used in the integrating model to move from the initial approximation to the equilibrium.

Regional Demands. National demand for each fuel is divided into a set of regional demands and regional prices using coefficients calculated from 1960-72 data. The regional share coefficients are calculated using regional value weighted shares of national demand, and the regional price coefficients are calculated by using the average relationship of regional to national prices. These regional share and price coefficients remain fixed over the 1973-85 period regardless of changes in relative energy prices. Then, given a regional demand calculated in this way and a regional price again calculated by a fixed weight index, the demand curve for the regional price-quantity pair is fixed by assuming that the demand elasticity is constant over the whole demand curve and is identical for all regions. Thus, say for the North Central region, the natural gas demand function is as shown in Figure 3.2.

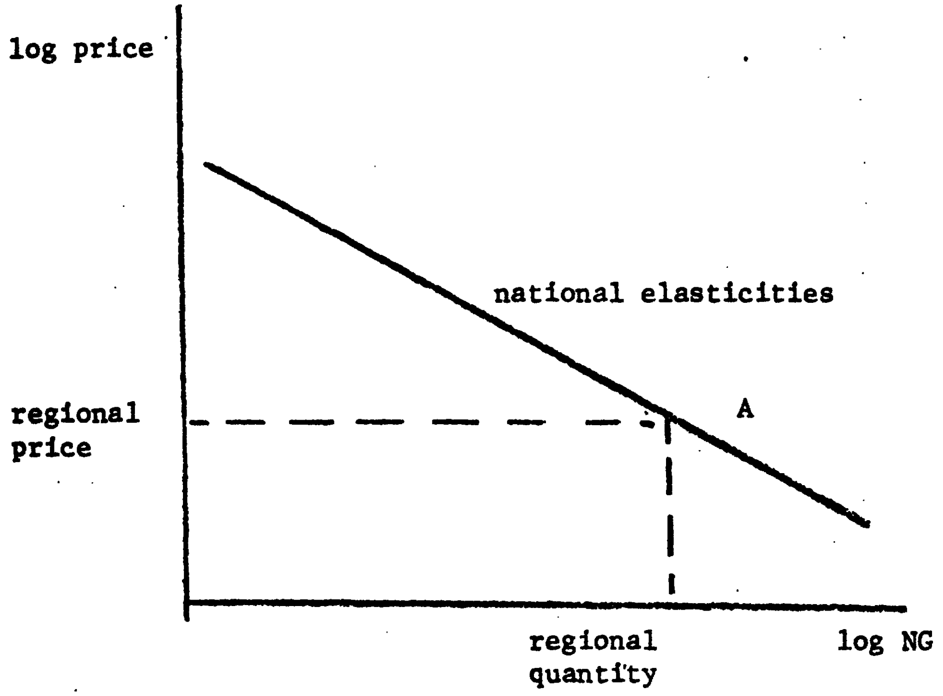

Figure 3.2: North Central 1985 Natural Gas Demand Function

The regional price (from the trajectory) and quantity (using 1973 weights) determine the point A, and the slope of the straight line (in logs) is determined by the national elasticity. The demand functions for all regions by assumption will have the same slope with their distance from the origin determined by the regional share and regional price coefficients. As can be seen in Figure 3.3 this assumption of parallel demand curves across regions is very stringent and likely to be a serious distortion of the actual situation.

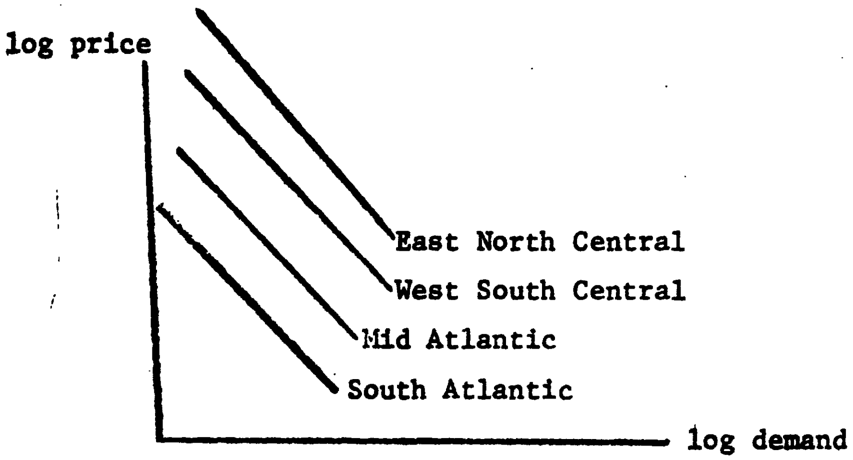

Figure 3.3. Regional Natural Gas Demand Functions

The Use of Regional Demand Functions Within the Integrating Model

Given these regional demand curves (with elasticities) as specified by the demand model, and given the supply curves, (discussed in Section 2), a Marshallian adjustment process is used to equilibrate the integrating model. That is, starting with a set of demands which result from the initial price trajectory shown in Table 3.2, the least cost supply distribution is calculated using the linear program integrating model. The integrating model produces "shadow prices" which are the implicit marginal prices of the regional energy supplies. These regional supply prices are compared to the demand prices on which the initial regional demand quantities were based. If the prices agree, a regional and national equilibrium has been attained and no adjustment is made. If the prices differ, then there is a two-step process to approach overall equilibrium. First, a price half-way in between the demand and supply price is used to calculate new regional demands using the national elasticity matrix:

$$\log D = \log D^{\circ} + M\,[\log P - \log P^{\circ}]$$

where D is the vector of regional demands, P the vector of the new regional demand prices with P° the old price vector and M is the matrix of own and cross price elasticities. With the new demands, a new LP solution is computed, and if the model and data are well behaved, the solution should converge to an overall supply-demand equilibrium. If equilibrium is attained, it will be characterized by different regional prices and energy shares, depending on the different transport costs and the characteristics of the M matrix.[1/]

Even if equilibrium is attained in the LP solution, there still may exist a disequilibrium in the system, for the resulting prices may drift far from the price assumptions that went into the original price index used in estimating aggregate national energy demand and national price elasticities. In this case, it would be necessary to cycle back through the whole demand forecasting model--starting with new trajectories and computing new demand paths and elasticity matrices. The reason this step is needed for equilibrium is that the positioning of the regional demand curves--not only the elasticity, but more importantly, their position in price-quantity space--depends on the original price trajectory chosen. This can be indicated on the following diagram, where D_1D_1 and D_2D_2 are 1985 demand functions resulting from two alternative price trajectories.

Both the position of DD^1 and its slope depend on the initial relative prices chosen and the dynamic character of the demand functions. Given a regional supply curve, it is very unlikely that it would pass through the intersection of D_1D_1' and D_2D_2'. To insure a full equilibrium once the

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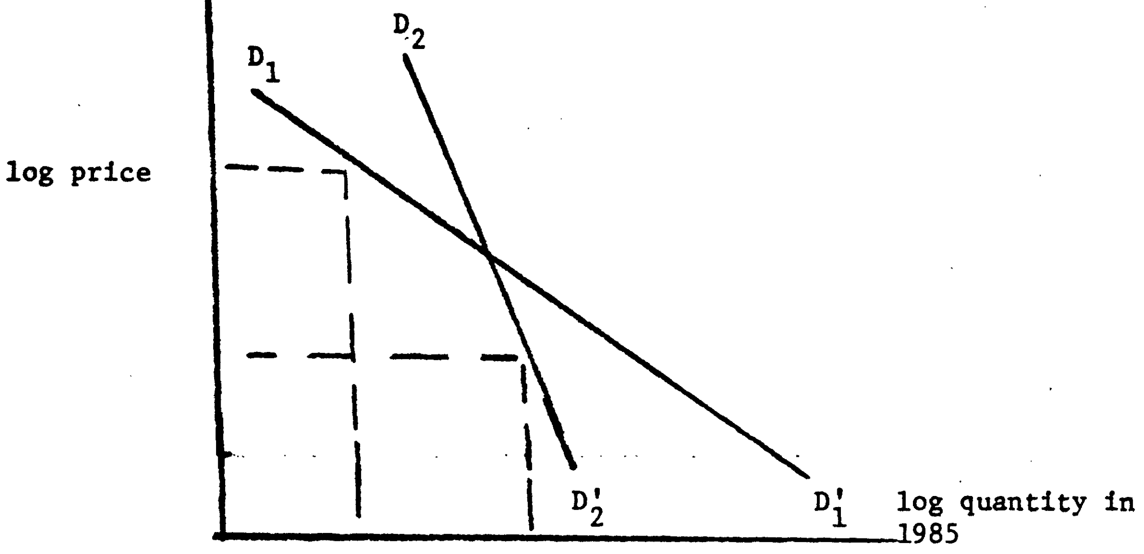
[1/] Output for the $11 "Business As Usual" scenario by demand region and products is presented in [1, Appendix IV, pp. 269-275].

Regional Fuel Demand Curve

Figure 3.2



integrating model provides equilibrium prices for, say, 1985, these prices would need to be used to generate a new set of prices with new regional demand curves computed. The equilibrium solution of these new demand curves would be used to form another new price set. If the procedure converged, a full equilibrium would be attained.

Another similar shortcoming is that once a full equilibrium of the supply-demand system is found, in principle these results should affect the level of macroeconomic activity which is used in forecasting total energy demand. That is, the forecasts of aggregate demand and investment should be sensitive to factor prices in the economy. Thus if the assumptions used to make the macro forecasts are not consistent with the energy prices and quantities, serious biases could result. The Blueprint assumes that the level of macroeconomic activity remains constant while the world oil price varies from \$4 to \$15. This assumption should be replaced by integrating the macroeconomic model with the energy model, a very difficult task.

Evaluation of the FEA Methodology

Estimation Problems: The FEA procedure in introducing demand into the integrating framework appears satisfactory in principle, but in practical application, given the data available during the study period, a number of serious problems are encountered.

The essence of the first problem can be seen in Table 3.2, which presents the own and cross elasticities for the Household and Commercial sector and for the Industrial sector. The model produces the counter-intuitive result that, in the Household and Commercial sector, natural gas and coal are complements of residual and distillate fuels rather than substitutes for them (that is, the cross elasticities are negative when they would be expected to be positive), so that as the price of oil rises the demand for natural gas falls in this model. Even in the industrial sector, the cross elasticity of coal demand to oil price is negative, and the cross elasticity of natural gas demand is essentially zero.[1]

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[1] The problem arising in this demand estimation can be seen in the following example considering a change in the demand for fuel oil. A rise in the price of natural gas decreases total energy demand (since the price index rises), but for a given total demand increases the share of residual fuel oil which is a close substitute for natural gas. Thus the cross price elasticity of residual demand with respect to natural gas price is:

$$\frac{png}{RES} \cdot \frac{d\,Res}{d\,png} = \left\{ \alpha_{res} \frac{d\,Tot}{d\,Pindex} \cdot \frac{d\,Pindex}{d\,png} + \frac{d\,\alpha_{res}}{d\,png} \cdot Tot \right\} \frac{png}{Res}$$

where demand for residual is $Res = \alpha_{res} \cdot Tot$, and $\sum_i \alpha_i = 1$. It is expected that the sign of the total derivative is positive, given that residual and natural gas are close substitutes. In fact, the FEA demand estimates must have the first term, the "output or income effect" being large and negative, for their estimates show natural gas and residual to be complements, not substitutes. While in theory the sign of the derivative is indeterminate, most analysts would find it very surprising that these fuels are complements. This problem likely arises from the restriction inherent in the demand share specification that the cross share elasticities are identical across all fuels for a given change in price of one fuel. Thus the second term is an average across all fuels and may not be large enough to give the expected relationship of substitutes.

Table 3.2*

Long Run Elasticities of Demand for Fuels in the Household and Commercial Sector 1985, $11 Scenario

	PNGHC	PELCH	PBIT	PDFL	PRF	POTH
ELCH	.128	-.444	.602	.084	.054	.032
NGH	-.368	.135	.011	-.063	-.08	.040
BITH	.888	.341	-.618	-1.384	-.147	.101
LGH	.358	.137	.012	.847	-.058	-1.605
KH	.014	.005	.001	-.029	-.002	-.087
DFLH	.289	.110	.009	-.638	-.047	.033
RFLH	.262	.099	.008	-.275	-.345	.029

Long Run Elasticities of Demand for Fuels in the Industrial Sector 1985, $11 Scenario

	PNGIND	PELCIND	PBIT	PDFL	PRF	POTH
ELCH	.294	-1.356	.149	.056	.128	.152
NGI	-1.506	.324	.067	.029	.085	.076
BITI	.816	.008	-.593	-.052	-.179	-.087
LGI	1.164	.008	.171	-.074	-.258	-1.148
KI	1.956	.016	-.622	-.12	-.46	-1.092
DFLI	1.158	.008	.225	-1.147	-.257	-.124
RFLI	1.176	.008	.593	-.076	-1.697	-.126
SGI	1.926	.016	.369	-.126	-.437	-2.058
PCI	1.830	.016	-.027	-.119	-.415	-1.568

Long Run Elasticities of Demand for Fuels in the Transportation Sector 1985, $11 Scenario

	PGAS	PNGI	PDFL	PRF
GAST	-.758			
LGT		-.355	-.069	-.258
DFLT			-.367	
RFLT			.191	-.191

*Reproduced from Tables AII-4, AII-5, and AII-6, PIR.

Now it is not altogether obvious what all the various factors are that contribute to this result, but clearly one very likely problem is that many of the observations on natural gas demand are on the supply rather than the demand curve. In the estimation procedure, the FEA properly omitted data from the early 1970's, when markets could no longer be assumed to be in supply-demand equilibrium due to shortages induced by FPC price regulation. The estimation of the fuel-split equations used data from the late 1950's and 1960's. During this period natural gas was simply unavailable in many areas of the country, although markets were expanding rapidly as new pipelines opened up new markets. As a result, one year there was little demand in a consumption region and the next year--after the pipeline was opened--there was a significant increase in the fuel share of natural gas, without any change in relative prices. If the estimation was regionally disaggregated, then it would be possible to introduce the fact that the gas price is essentially infinite before the pipeline is built to a region, but in an estimation based on national aggregates this essential fact is obscured, and the result is that a supposed estimation of the demand curve is confounded by estimates that really are points on a shifting supply curve.

In addition to the problem of complementarity between gas and oil products, many of the own price elasticities in Table 3.2 seem very high. For industrial demand these high elasticities occur because of fuel availability and locational effects and use of average rather than marginal price for electricity in demand estimation, while in transportation they likely stem from the problem of disentangling price and income effects in the demand for gasoline. These problems require careful treatment in any case. However, in a logit-type analysis they are difficult to deal with because shares change very slowly over time.

Another problem may arise due to the specification of energy demands in the industrial sector. Energy is an intermediate good, and the usual way of dealing with derived or intermediate demand is to estimate final goods consumption as a function of income and final goods prices, and then determine demand for factors (e.g., energy) through a production technology which is a function of output and price of (all) factors of production. It is legitimate to collapse demand for final goods and the production technology into derived demand for factors; but then the derived demand must be a function of income and all factor prices. Using only energy prices in specifying demand constitutes a misspecification because the other factor prices (e.g., wages, cost of capital, cost of other raw materials) have been omitted. Ideally, the energy prices would be determined from crude oil, wellhead gas, and minemouth coal prices by refining and transportation technologies. While lack of data often precludes correct econometric practice, this consideration would be important in determining the interaction of energy prices and GNP growth.

Effect on the Overall Demand Estimate: Given the underlying structure implied by the results shown in Table 3.2, it is not surprising that the initial demand forecasts prepared by FEA using the model gave what appeared to be serious underestimates of the demand for natural gas, particularly at high oil prices.[1/] (For example, the model has a higher equilibrium price

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[1/] Industrial coal demand also drops as oil prices rise, for the same reason, although the significance of this effect is dampened somewhat by the fact that so much coal demand is in the electric sector, which is handled in another way.

of natural gas at $4 oil than at $11 oil, and more natural gas is consumed with $4 oil than with $11 oil)[1]

It is apparent that some considerable effort went into attempts to correct the problem once the counter-intuitive nature of the results was seen. For one thing, the elasticity matrix that resulted from the procedure described above was "doctored" to force the model to yield more reasonable results. Thus, as pointed out in the PIR [1, p. A87], the elasticities of demand to industrial electricity price and household and commercial natural gas price (Table 3.2) were scaled down by factors of six and four respectively as part of this process of imposing judgment on the econometric results. The precise reason for this adjustment, and its effect on the results, are not known.

Another form of adjustment of the model to this problem of the disappearance of natural gas demand at high oil prices was in the handling of the original price trajectories shown in Table 3.1. In this case the effect on the results is more clear, and damaging. As can be seen in Table 3.1, the natural gas prices were held constant under all oil price scenarios at a price roughly equivalent to $7 per barrel oil. The endpoint of the natural gas price trajectory is not raised when oil prices rise to $11 per barrel for the reason noted earlier, i.e., the natural gas demand falls to unreasonably low levels when this is done. The reason, of course, that natural gas demand falls when the oil price rises is because of the incorrect sign in the cross elasticity of natural gas and oil products.

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[1] Problems with natural gas exist with supply as well as demand as discussed in Section 2. Both supply and demand misspecification lead to underestimating the amount of gas consumed, especially as the price of oil rises beyond $7.

By keeping the natural gas price low in the trajectory, at least some consumption of natural gas is retained when the oil price rises. However, this is an ad hoc adjustment which creates additional problems.

It is important to notice the effect of this assumption about price trajectory for natural gas, coupled with the elasticities in Table 3.2 on the solution to the integrating model. As oil price rises, natural gas demand does not rise. As a result the price of natural gas in the integrating model is never driven away from this starting assumption because, in effect, gas supply is never driven up onto the inelastic portion of the supply function.[1/] In fact in some regions, gas prices fall below those implicit in the vector of initial demands. Three points need to be made about this set of problems:

(1) Failure to Achieve BTU Equilibrium

Under the "deregulation" assumptions of the PIR, by 1985 sufficient time should have passed so that energy sources which are nearly perfect substitutes for each other (e.g., natural gas and distillate) should be in equilibrium with respect to BTU price (after counting in all transportation and distribution costs). Using the PIR BTU conversion rates [1, p. A281] and the city-gate equilibrium prices for distillate, for, say, the Mid-Atlantic region, the BTU price of distillate is $2.04/million BTU's [1, p. 273] and the price of natural gas is $1.14/MCF [1, p. A272]. Therefore, a BTU of gas costs only 54% of a BTU of distillate fuel oil. From elementary cost minimization assumptions, an

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[1/] This cheap gas is not picked up by the electric power sector because the model is constrained not to install gas-fired generating capacity.

industry buying at the city gate should buy only natural gas. Household and commercial users, even after allowing for within city markups and retail delivery costs should also buy only natural gas. Yet the model has 3,130 million BTU's of distillate being consumed in 1985 in the Mid-Atlantic region.[1/]

To calculate a BTU equilibrium all appropriate costs including transportation, storage costs, etc., plus the effects of long term contracts must be taken into account. Still the most powerful notion of the economic calculus states that <u>close substitutes cannot have greatly different prices</u>. Thus, even when all the complications are considered, the <u>large price disparity between, say, distillate and natural gas could not exist in a true equilibrium under deregulation. This consideration must be of extreme importance in determining the role of alternative fuels such as coal, natural gas, and synthetics in 1985</u>.

(2) <u>Overestimation of Overall Energy Demand</u>.

Since the natural gas price is never raised above the level shown in Table 3.1, the price index used in forecasting national energy demand is underestimated in relation to what it would be if the model were yielding something closer to BTU equilibrium, and thus the aggregate demand is overestimated.

[1/] The situation for coal is less clear due to different burning efficiency and capital cost requirements, but again the price of coal seems well out of equilibrium even allowing for these additional complications.

(3) Underestimate of National Gas Consumption

The problem of lost demand for natural gas remains, and in effect the share of oil (and thus of imports) in overall aggregate demand also appears to be overestimated. As the oil price rises, the share of natural gas must increase, not decrease, as the PIR forecasts. The PIR in effect continues the natural gas shortage due to current regulatory policies. To appreciate the effect of regulation and the size of the natural gas shortage if it is continued, the model must be corrected so that reasonable demand forecasts are made.

These problems are critical for policy evaluation. In an experiment in which approximate BTU equilibrium prices for gas, coal, and electricity for $11 oil are used in the original price trajectory, the final equilibrium gas price rises almost 25% above the Blueprint estimate.[1] Furthermore, forecast equilibrium oil imports are reduced by almost a million barrels a day. If the cross elasticity of natural gas with oil products had the correct sign, it is likely that oil imports would have fallen even further given more realistic supply estimates of natural gas. Comparing the PIR $11 oil results with this attempt at a $11 oil "BTU equilibrium" solution shows the marked changes. Thus crucial policy questions such as the level of oil imports are dependent on the price trajectory used in the integrating model. Furthermore, as expected when a BTU equilibrium is approached gas and coal have a more important role than the Blueprint finds.

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[1] In this "BTU equilibrium" run I did not "doctor" the electricity and gas price elasticities in the industrial sector as the PIR does. This experiment is meant to be suggestive of how the important policy results can change with corrections to the model assumptions. However, the basic problem of incorrect demand estimates cannot be corrected in such an experiment.

Total Energy Consumption for $11 Oil

	PIR	BTU Equil.	Percent Change
Coal (mill. tons)	1,005	1,131	+11.8%
Petroleum (mill. barrels)	6,989	6,650	-5.0%
Gas (bill. c.f.)	24,007	27,055	+12.0%
Petroleum Imports (mill. bar/day)	3.33	2.45	-30.7%

Equilibrium Prices for Three Regions: New England, Middle Atlantic, West North Central

		PIR	BTU Equil.	Percent Change
Gas	NE	$ 1.18	$ 1.48	+22.7%
	MA	1.14	1.44	+23.4%
	WNC	.98	1.21	+21.8%
Coal	NE	19.19	21.02	+9.1%
	MA	16.01	17.84	+10.8%
	WNC	15.12	15.20	+0.7%
Residual	NE	10.60	10.69	+0.8%
	MA	10.60	10.69	+0.8%
	WNC	10.74	10.83	+0.8%
Distillate	NE	11.90	12.33	+3.5%
	MA	11.88	12.30	+3.5%
	WNC	11.79	12.19	+3.3%

4. Summary

The PIR takes an important problem and proposes a complex model to evaluate the U.S. energy situation over a relatively long period of time, 1973-1985. It is an impressive initial attempt to construct a flexible model so that proposed energy policies may be evaluated within a common framework. However, very serious problems exist with the PIR model. The major problems which should be carefully considered before using the PIR model are:

(1) A set of very stringent deregulation assumptions and material availability assumptions are made in the PIR. If these assumptions do not hold over time, the results in the PIR may prove to be quite sensitive to the assumptions. Further evaluation of the model is required to estimate the importance of possible nonfulfillment of the assumptions.

(2) The energy model is not integrated within a macroeconomic model. Rather, the macroeconomic variables are taken as exogenous. While the PIR finds little effect of higher energy prices on GNP and other macroeconomic factors, this result should be treated with skepticism due to the modeling technique used.

(3) The modeling approach used in the oil and natural gas supply models is seriously deficient. The most important factors are taken as exogenous to the models and responsiveness of supply to price changes is underestimated. Nonassociated gas supply is found to be totally price inelastic; this result is incorrect and is a result of incorrect "target rates" set exogenously. Due to the supply models used, the importance of deregulation of domestic energy prices in increasing domestic energy supply is obscured.

(4) A key result of the supply model and integrating model, the increasingly important role of electricity generation, is sensitive to sufficient financing being available and other obstructions to the construction of nuclear and coal electricity generating capacity being removed. Due to the long lead times involved, if current policies are not changed soon electricity will not expand nearly so much as the PIR forecasts.

(5) The demand model and its interaction with the integrating model lead to downward biased estimates of the consumption of natural gas and perhaps coal. The model lacks a "BTU equilibrium" so that in 1985 the PIR forecasts the (deregulated) price of natural gas to be about half that of oil on an equivalent BTU basis. Furthermore gas and oil products are found to be complements, not substitutes, as common sense says they must be so that the PIR forecasts less gas to be consumed with $11 oil than with $4 oil prices.

(6) Under the assumed price conditions, the FEA tends to overstate the likely level of net imports of oil in 1985. If natural gas supply is in the least price elastic and if natural gas and oil products are substitutes, the PIR has an upward biased forecast of oil imports. Further depressing effects on imports might also come through the effect of higher energy prices on GNP growth. Thus I am considerably more optimistic than the PIR on domestic energy supply and demand.

To the extent that the assumptions of the PIR do not come about, my conclusions about the likely biases of the PIR forecasts may not be fulfilled. Yet within their assumed framework, the U.S. could well become a net exporter of energy in 1985 at well below the $11 price where the PIR forecasts oil imports to be above 3 million barrels per day. Apparent support for President Ford's tariff proposals which the model currently shows are likely due to the biases inherent in the model. Therefore before the PIR model is used for policy evaluation purposes, the obvious faults must be corrected. Otherwise, conclusions drawn from the model are invalid; and policy formulation which uses the model as input is accepting seriously biased forecasts of the likely state of energy imports over the next decade.

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