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SUMMARY OF ENERGY SUPPLY,
DEMAND, AND PRICING EVALUATIONS

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Final Report

on

SUMMARY OF ENERGY SUPPLY, DEMAND, AND PRICING EVALUATIONS

Report Prepared

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SUMMARY OF ENERGY SUPPLY, DEMAND, AND PRICING EVALUATIONS

Introduction

Since the fall of 1973 when the statistics and forecasts for *Texas Energy* were developed, the state of Texas has supported continued efforts to update the initial work done at the University of Houston by Thompson *et al*. One of the first follow-up efforts was made by the Texas Governor's Energy Advisory Council chaired by Lieutenant Governor William P. Hobby in 1974. This Advisory Council sought to make a comprehensive assessment of the important technical, economic, legal, and institutional considerations of long-run importance for the future growth of Texas. The economic results of this study showed how the increasing scarcity of oil and gas in the nation would result in generally higher prices of oil and gas and continued expansion of petroleum supplies in the eighties and early nineties. Texans were found to benefit economically from the favorable supply effects in spite of the decreased use of oil, gas, and electricity products at the higher prices; see Thompson *et al*.(1975), Holloway *et al*. (1975) and Finch *et al*. (1975) for further information.

University of Houston 1976 Studies for The Energy Institute

Later studies by Thompson *et al.* (1976) at the University of Houston showed the importance of considering different energy and environmental policies. They found the great imbalance in the United States energy market was basically evolving out of a growing excess demand in the natural gas market where interstate prices were regulated far below the market-clearing level before mid-1976. Results of the study showed deregulation of natural gas prices and continued regulation of domestic crude oil prices (partial deregulation) would give by far the lowest consumer bill for energy in the United States in 1985.

The policy option stimulates domestic production of natural gas at a cost less than the Btu equivalent cost of imported crude oil at the high OPEC price. Complete deregulation increases production and decreases use more than partial deregulation; however, the higher price of oil is paid for old as well as new production. Higher costs of old oil could be offset by a windfall profit tax, if the United States has enough economic and political clout in foreign policy to keep OPEC from ratcheting up the price of crude oil to exorbitant levels.

University of Houston 1976 Studies for Advisory Council

Anticipating the Federal Power Commission's increase in the interstate natural gas price from $.52 to $1.42 per 1000 cubic feet, the Texas Governor's Energy Advisory Council contracted with the University of Houston to evaluate the following basic energy-pricing questions for a target year of 1985:

- How will continued regulation of domestic crude oil and interstate natural gas prices affect the consumer energy bill, crude oil imports, energy prices, domestic production, energy use, and sulfur discharges?
- How will the economic and resource consequences of deregulating gas prices but not oil prices (partial deregulation) compare with the continued regulation of gas prices at the higher 1976 level of $1.42 per 1000 cubic feet?
- What will be the primary differences in the economic and resource consequences of a partial deregulation policy option versus a complete deregulation policy option for oil and gas prices?

Additional analyses were made for the partial deregulation case to answer the following questions:

- What will be the economic consequences of prohibiting the building of new base load electric power plants to burn oil and gas products?
- What will be the consumer costs of a prohibition policy for oil and gas fuels plus a strict environmental policy for sulfur dioxide emissions (new source standards for sulfur dioxide emissions in old as well as new plants)?
- What will be the costs to the consumer of a nuclear moratorium in addition to prohibition of oil and gas in new base load electric power plants?

Further improvements of the supply, demand, and industry models were made to answer these questions for the Advisory Council. Much improved models for economic supplies of coal [FEA, 1976] and oil and gas [Kim and Thompson, 1977] were included in Thompson's model. Also, the industry models were updated to include additional processes and the latest costs of pollution control. Estimates of demands for modeled end products were also revised in accordance with current data on production levels. Regional delineations were made between coal produced in Eastern, Midwestern and Western regions to reflect differences in Btu and sulfur content. Regional delineations were also made between coal and electricity use in Eastern and Western regions of the nation to reflect differences in the costs of transportation for coal.

Specifications and Assumptions

The following specifications and assumptions were made in the modeling to answer the three basic questions for 1985 (1975 dollars are used throughout):

- Imports of crude oil and residual fuel oil are available, as needed, at \$13 per barrel; limited imports (up to 3 trillion cubic feet per year) of liquefied natural gas are available at \$2.50 per 1000 cubic feet.
- Estimates of domestic supplies of new crude oil and natural gas assume no depletion allowance, continued deductions of intangible and dryhole drilling costs, and a future finding rate corresponding to the U. S. Geological Survey's average estimate of reserves.

- Domestic supplies of crude oil and natural gas are priced as follows: Continued Regulation -- old oil \$6.20 per barrel and new oil \$10.20 per barrel; old gas \$0.80 per 1000 cubic feet and new gas \$1.42 per 1000 cubic feet; Partial Deregulation -- same as Continued Regulation except new natural gas is priced at the market-clearing level; Complete Deregulation -- market-clearing prices for old and and new crude oil and for new natural gas.
- Use of best available technology standards for waste-water effluents and new source standards for air emissions from new plants. Old source standards for air emissions from old plants are required except where stated otherwise. Sulfur content of fuels sold to the residential/commercial sectors must meet new source air emission standards.
- Capacities of old fossil steam electric power plants were based on National Electric Research Council estimates [1975].
- Ranges of retirement rates for old electric power plants between 1975 and 1985 were from 10 to 30 percent for coal, oil, and gas-fired plants and from 0 to 5 percent for combined-cycle plants.
- Annual supplies of electricity from nuclear generation are 368.3 billion kilowatt hours for the Eastern region and 372.8 billion kilowatt hours for the Western region

of the nation.

- Annual supplies of electricity from hydroelectric generation are 113.6 billion kilowatt hours for the Eastern region and 345.9 billion kilowatt hours for the Western region.
- FEA's economic demands for important energy end products [1976] basically reflect consumers' response to price.
- The real rate of growth in the economy from 1975 to 1985 will average 3 percent per year (1.2% for population and 1.8% for real per-capita income).

Results of the Modeling Evaluations for 1985

Basic Policy Evaluations

Continued Regulation vs. Partial Deregulation. -- Comparison of the modeling results for Cases 1 and 2 in Table 1 shows the Federal Power Commission's mid-1976 order to raise the ceiling price of interstate natural gas from $0.52 to $1.42/Mcf almost deregulated the 1985 wellhead price of natural gas in interstate commerce. The market-clearing price of $1.54/Mcf in the Partial Deregulation Case is only 12 cents higher than the regulated price of $1.42/Mcf in the Continued Regulated Case. This higher market-clearing price results in an additional 500 billion cubic feet of natural gas for use in the nation.

In the Continued Regulation Case, investment in new electricity generation favors coal fired steam-electric plants rather than gas-fired

TABLE 1. University of Houston Energy Institute Pricing Evaluations for Texas Governor's Energy Advisory Council; Modeling Evaluations for 1985.

Category	Fossil Energy Source		1975 Statistics	Basic Policy Cases: Continued Regulation (Case 1)	Partial Deregulation (Case 2)	Complete Deregulation (Case 3)
SUPPLIES	Crude Oil* (billion Bbls.)	Domestic	3.65	4.44	4.45	4.93
		Imported	2.22	2.58	2.56	2.08
		Total	5.87	7.02	7.01	7.02
	Natural Gas† (TCF)		20.1	21.92	22.42	22.74
	Coal (MM s. ton)		640	949	924	902
AVERAGE PRICES (1975 $)	Oil ($/Bbl. wellhead)		-	10.52	10.52	13.07
	Natural Gas ($/Mcf wellhead)		-	1.31	1.31	1.31
	Coal ($/s. ton minemouth)		-	13.39	13.29	13.19
FOSSIL ENERGY USE (quad Btu)	Oil		32.98	38.60	38.56	38.66
	Natural Gas		18.25	22.62	23.14	23.50
	Coal		15.60	20.73	20.19	19.69
		TOTAL	66.83	81.95	81.89	81.85
CONSUMER BURDEN (billion 1975 $)	Oil		-	73.81	73.75	91.75
	Natural Gas		-	28.79	29.47	29.91
	Coal		-	12.71	12.28	11.89
		TOTAL		115.31	115.50	133.55
Unit Fuel Cost ($/mmBtu) All Fossil			-	1.41	1.41	1.63
Oil Foreign Exchange Payments (Bil.$ 1976)			28.9	33.56	33.35	27.07
Sulfur Dioxide Discharges (Bil. lbs.)			-	36.95	36.32	35.63
Capital Requirements of Electric Utilities for Fossil-Fueled Plants from 1975 through 1985 (Bil.$ 1976)			-	51.05	50.12	49.31

* Includes natural gas liquids

† Includes associated gas

combined cycle plants, because of the scarcity of natural gas. East Coast electric utilities build 141 million kilowatt hours of new combined-cycle capacity and 287 billion kilowatt hours of new coal-fired capacity in the Continued Regulation Case; however, East Coast electric utilities build 71 billion kilowatt hours of new combined-cycle capacity and 216 billion kilowatt hours of new coal-fired capacity in the Partial Deregulation Case. No new combined-cycle capacity is built in the Central Region in either the Continued Regulation or the Partial Deregulation Cases. Neither new gas nor oil-fired steam-electric plants are built in any of the cases evaluated.

With the increased quantity supplied of natural gas in the Partial Deregulation Case, the demand for coal contracts by 25 million short tons, primarily because of the shift from new coal steam-electric to new gas combined-cycle plants on the East Coast. This contraction in the demand for coal virtually offsets the increased use of gas to give almost the same consumer burden in Continued Regulation and Partial Deregulation Cases.

The consumer burden represents costs of oil liquids, natural gas, and coal products at input prices in the Continued Regulation Case; in the Partial Regulation Case this burden represents costs of oil liquids, old natural gas, and coal products at input prices and costs of new natural gas at marginal costs. A penalty of $1.91 billion is assumed in the Continued Regulation Case for the net welfare loss from a lack of available gas (value of new natural gas produced at marginal value less the value of the new natural gas produced at the regulated price).

Capital requirements of electric utilities for investments in new coal and gas fired plants are \$930 million greater in the Continued Regulation Case (\$51.05 billion) than in the Partial Deregulation Case (\$50.12 billion) for the ten-year period from 1975 through 1985. The primary reason why investments are larger in the Continued Regulation Case is the need to invest in new coal-fired steam electric plants on the East Coast.

Foreign exchange payments are slightly greater in the Continued Regulation Case (\$33.56 billion) than in the Partial Deregulation Case (\$33.35 billion). This level of foreign exchange payments is very similar to the level paid for imported crude oil in 1976.

Partial vs. Complete Deregulation

Allowing the prices of oil and gas to seek their market-clearing levels in the Complete Deregulation Case increases the domestic production of crude oil by 480 million barrels from the Partial Deregulation Case. With the higher price of crude oil, the supply of natural gas in the Complete Deregulation Case expands by 320 billion cubic feet from the level in the Partial Deregulation Case. The market for crude oil reaches equilibrium at the import price of \$13/bbl; the market for natural gas reaches equilibrium at a market-clearing price of \$1.53/Mcf. Increased availabilities of domestic crude oil and natural gas contracts the demand for coal in a completely unregulated market by a total of 22 million short tons from the level in the partially regulated market.

Increased domestic production of crude oil virtually offsets decreased imports of crude oil to result in slightly larger use of oil liquids in the free market. Increased production and use of natural gas provides the remaining offset to the decreased production and use of coal. Fossil energy use in the nation totals almost the same in both cases.

Because of increased gas supplies, still larger investments in combined cycle electric power plants are made in the Complete Deregulation Case (118 billion kilowatt hours) than in the Partial Deregulation Case (71 billion kilowatt hours). This increase in gas-fired combined-cycle capacity exactly offsets the decrease in coal-fired steam-electric capacity on the East Coast. Capital requirements for investments in fossil-fueled electric power plants falls by $810 million in going from the partially free to the totally free oil and gas markets.

Because of the substitution of domestic production for foreign production, foreign exchange payments are $6.28 billion less in the Complete Deregulation than in the Partial Deregulation Case. Imposition of a windfall profits tax on the production of oil liquids from old wells would decrease the consumer's fossil energy burden for domestic crude oil by $8.5 billion. Economic considerations beyond the fossil energy sector are required to justify extending deregulation to oil as well as gas prices, because the United States is a price taker rather than a price maker in the world oil market.

Alternative Policy Options for Partial Deregulation

With the deregulation of gas but not oil prices, prohibiting the use of oil and gas products in new base load electric power plants (except for operation of air emission control equipment) decreases the market-clearing price for new gas from $1.54/Mcf in Case 2 to $1.49/Mcf in Case 4. This lower price decreases slightly the production of natural gas and the consumer burden for natural gas; see Table 2. Domestic production, foreign imports, and total use of crude oil are virtually the same in the two cases. Demand for coal expands by 20 million short tons to fill the void created by the inability to build new combined-cycle plants on the East coast. A slightly higher coal price is required to bring forth 19 million short tons of additional low-sulfur coal production. Capital requirements in electric power generation increase by $680 million in order to build the more expensive coal burning plants.

A combination of partial deregulation, oil and gas prohibition in electricity generation, and strict standards for sulfur dioxide emissions in both old and new electric power plants expands the demand for coal in Case 5 still more than found in Case 4, where strict standards are applied only to new plants. An additional 39 million short tons of coal is used in Case 5 to produce the larger requirements for electricity (24 billion kilowatt hours). Approximately 58 percent of the increase in electricity requirements results from the fuel requirement penalty in use of stack-gas scrubbers to meet the strict sulfur emission standards in old as well as new plants. Electric utilities seek to avoid paying this scrubber penalty by increasing the use of Western low-sulfur coal by 155 million short tons and decreasing the use of Eastern and Midwestern higher-sulfur coals by 116 million short tons. Also, these utilities seek to avoid this scrubber penalty by substituting about 300 million barrels of desulfurized residual fuel oil imports for dirty raw crude oil imports.

Imposition of new source sulfur dioxide emission standards for all electric power plants stimulates maximum possible replacement of old coal-fired plants with new coal-fired plants. Electricity production in old coal-fired plants falls from 282 billion kilowatt hours in Case 4 to 219 billion kilowatt hours in Case 5. This decreased generation in old plants is more than offset by the increased generation in new plants (83 billion kilowatt hours).

Additional capital requirements of $11 billion are incurred in Case 5 to accomplish the new source standards in old as well as new power plants. Seventy-four percent of this increased capital investment is made by East Coast utilities. With these new plants, sulfur dioxide emissions decrease 11.84 billion pounds in the nation. However, this decrease is accomplished at a 4 mill increase in electricity costs per kilowatt hour (1.03 mills in Case 4 vs. 1.07 mills in Case 5).

Imposing a moratorium on the construction of new nuclear power plants in addition to prohibiting the use of oil and gas products in new electric power plants expands the use of coal in Case 6 to 1021 million short tons as compared to 983 in Case 5. However, the incidence of the moratorium in Case 6 is considerably different than the incidence of the strict sulfur standards in Case 5. Maximum use is made of old coal plants in Case 6; investments in new coal plants are made in both the Central and Eastern Regions to fill the void left by unbuilt nuclear plants and to satisfy forecast growth in electricity requirements. Capital requirements for fossil-fueled electric utilities in Case 6 are greater than capital requirements for these utilities in any one of the Cases 1 through 5.

TABLE 2. University of Houston Energy Institute Pricing Evaluations for Texas Governor's Energy Advisory Council; Deregulation of Natural Gas, but Not Crude Oil Prices; Modeling Evaluations for 1985.

Category	Fossil Energy Source		Alternative Policy Options for Partial Deregulation		
			Prohibition of Oil and Gas Use in Electric Power Generation (Case 4)	Oil and Gas Prohibition plus Strict Sulfur Dioxide Standards (Case 5)	Oil and Gas Prohibition plus Nuclear Moratorium (Case 6)
SUPPLIES	Crude Oil* (billion Bbls.)	Domestic	4.44	4.44	4.44
		Imported	2.57	2.56	2.60
		TOTAL	7.01	7.00	7.04
	Natural Gas ** (TCF)		22.21	22.27	22.26
	Coal (MM s. ton)		944	983	1021
AVERAGE PRICES (1975 $)	Oil ($/Bbl. wellhead)		10.53	10.51	10.52
	Natural Gas ($/Mcf wellhead)		1.28	1.28	1.28
	Coal ($/s. ton minemouth)		13.39	12.13	13.69
FOSSIL ENERGY USE (quad Btu)	Oil		38.59	38.78	38.71
	Natural Gas		22.92	22.98	22.98
	Coal		20.63	20.49	22.23
		TOTAL	82.14	82.25	83.92
CONSUMER BURDEN (billion 1976 $)	Oil		73.81	73.64	74.09
	Natural Gas		28.38	28.49	28.43
	Coal		12.63	11.92	13.98
		TOTAL	114.82	114.05	116.50
Unit Fuel Cost ($/mmBtu) All Fossil			1.40	1.39	1.39
Oil Foreign Exchange Payments (Bil $ 1976)			33.45	33.28	33.73
Sulfur Dioxide Discharges (Bil. lbs.)			36.84	25.0	38.84
Capital Requirements of Electric Utilities for Fossil-Fueled Plants through 1985 (Bil 1975 $)			50.80	61.80	62.06

*Includes natural gas liquids

**Includes associated gas

Comparison of Fossil Energy Bills for Marginal and Input Prices

The results in Table 3 show the 1985 fossil energy bills for the six cases evaluated, where the bills are calculated both at the marginal costs of the model and at the final input prices to the model. Nearly equal fossil energy bills are found at marginal cost prices in the different energy pricing considerations of Cases 1, 2 and 3. However, noticeable differences are found between the fossil energy bills calculated at input prices and the fossil energy bills calculated at marginal costs in these three cases.

The greatest difference in the method of computing the bill exists in the Continued Regulation Case, where the least economic efficiency in the allocation of energy resources occurs; and the least difference in the method of computing the bill exists in the Complete Deregulation Case, where the greatest economic efficiency in the allocation of energy resources occurs.

Slightly smaller, but still relatively large resource inefficiencies are indicated by the results of Cases 2, 4, 5 and 6. Deregulation of natural gas prices in Case 2 gives a smaller indication of resource misallocation than Continued Regulation of natural gas (and crude oil) prices in Case 1. However, this indication of resource misallocation at the \$1.42/Mcf regulated price of interstate natural gas is relatively small in comparison to the indication of resource misallocation at the current regulated prices of domestic crude oil.

TABLE 3. 1985 Fossil Energy Bills at Input Prices and Marginal Costs for Six Cases Evaluated.

Case	Input Prices	Marginal Costs
	(bil. 1975 $)	
1	113.4	137.2
2	115.5	137.3
3	132.9	137.6
4	114.8	136.3
5	114.1	136.4
6	116.5	138.0

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APPENDIX I

COAL SUPPLY, BENEFICIATION, AND TRANSPORTATION

Briefly, economic supplies of coal produced in the Eastern, Midwestern, and Western Regions of the nation were developed as follows: price-quantity data were extracted from FEA's Coal Report (1976) with key states being selected for each major producing region; each supply point was categorized according to Btu content and sulfur content; FEA's regions were aggregated into Eastern, Midwestern, and Western Regions; and FEA's many coal type classifications were aggregated to give four coal types: Eastern High Sulfur (EHC), Eastern Low Sulfur (ELC), Midwestern High Sulfur (MHC), and Western Low Sulfur (WLC); FEA data within the four coal types were summed to give four step-function supply curves for coal; and piecewise linear approximations of each step-function were used to derive a price-quantity pairing for each coal type.

Central and Eastern coal consuming regions are used in the model to prevent large quantities of western low sulfur coal from being shipped to the electric power industry on the East Coast at an unrealistically low price. The Central coal consuming region is assumed to consist of the states west of the Appalachian Mountains; and the Eastern coal consuming region is assumed to consist of the states east of the Appalachians. Areas served by barge transport on the Mississippi and Ohio Rivers are included in the Central Region.

All of the petroleum refining and chemicals industries are assumed to be in the Central Consumption Region to minimize computational time. No provisions are made for other special regions like the West Coast of the United States. See Appendix II for a description of how coal was modeled and updates were made in the environmental costs.

Coal Supply for the Model

Coal supply curves were developed for the model based on the data and methodology used during 1975-76 in the Project Independence Evaluation System (PIES) of the Federal Energy Administration (FEA). The PIES coal supply methodology is based on Bureau of Mines reserve base estimates of coal tonnage and quality characteristics by seam and county (FEA, 1976). The PIES methodology assigns Bureau of Mines coal reserves to 32 product quality categories (8 sulfur content ranges x 4 Btu content ranges), and to a large number of mine type categories. Mine type categories are differentiated by surface or deep mine technology, size of mine, and depth and thickness of coal seam. For surface mines the depth below ground and thickness of a coal seam are combined to give the parameter "overburden ratio," the ratio of cubic yards of overburden material removed per ton of coal mined. In the PIES analysis a mining cost model was used to develop capital and operating costs for each mine type. The PIES methodology thus defines a set of hypothetical coal mines that exploit the entire U.S. coal reserves as defined by the Bureau of Mines.

In the PIES methodology a fraction of the entire set of hypothetical coal mines is identified as corresponding to existing U.S. capacity. Coal is assumed to be produced by these mines provided the market price covers variable costs of production. The remaining mines are mines built after 1976 and are only brought into production when the market price covers all costs plus 8% per year return on investment.

In the PIES model supply curves are generated by aggregation of the hypothetical coal mines over 12 geographical regions and three product types: metallurgical coal, low sulfur coal, and high sulfur coal. Metallurgical coal is defined as coal in the highest PIES Btu content range (greater than 26 million Btu per ton) and the two lowest sulfur content categories (less than 0.6 lb sulfur per million Btu). PIES low sulfur coal is defined as coal which does not meet metallurgical specifications but has a sulfur content of less than 0.72 lb sulfur per million Btu. PIES low sulfur coal is defined such that it meets EPA new source SO_x performance standards (1.2 lb SO_2/MMBtu coal) either as is or after beneficiation. PIES high sulfur coal is defined as all coal which contains more than 0.72 lb sulfur per million Btu.

For the work reported here, the 12 PIES geographical regions were aggregated into three regions: the three PIES Appalachian regions were combined into one Eastern region; the PIES Midwest and Central-West regions were combined and designated Midwestern; and the PIES Western Northern Great Plains region (western Montana, Wyoming, and northern Colorado) was taken to represent the Western region for the model. Further, coal was allocated into four representative types: eastern low sulfur coal type (code ELC), eastern high sulfur (EHC), midwestern high sulfur (MHC), and western low sulfur (WLC) coals. Coals MHC and WLC were defined as all coal in the midwestern and western regions, respectively, with the exception of metallurgical grades. The eastern region has coal with a very wide range of sulfur contents, and coal types ELC and EHC are defined such that roughly half of the eastern non-metallurgical coal reserves are in each representative type. Type

ELC is defined as coal with a sulfur content of less than 1.68 lb/million Btu but not meeting metallurgical quality standards. Type EHC is defined as coal exceeding 1.68 lb/million Btu in sulfur content.

A supply curve was generated from the PIES mine cost data for each of the four representative coal types. This was done by assigning each PIES hypothetical coal mine to the appropriate representative coal type. The mine data for each type were then arranged in order of increasing coal selling price, and selling price was plotted versus cumulative mine capacity to give a supply curve consisting of a large number of small discrete stair-steps, with each step representing the addition of one or more mines to the production base. It was found that these supply curves could be well represented by sets of 3 to 6 straight-line segments fitted to the stair-steps. Table 1 presents the supply curves for the four representative coal types. If the price-quantity data in Table 1 are plotted and the points connected by straight lines, the supply curves are obtained.

Representative ash, sulfur, and Btu contents were assigned to each of the four coal types. Ash content of the coal was not specified in the PIES data. Ash content of coal varies widely, but it does not show any pronounced trends from region to region (Deurbrouck, 1972). Accordingly, all types of coal were assumed to have the same ash content, 17% by weight. As the cumulative production quantities were computed for the supply curves, cumulative average sulfur and Btu contents were also computed. As individual mines with differing coal qualities are added to the production base, the cumulative average sulfur and Btu contents vary slightly. The

APPENDIX TABLE 1. Points Defining Straight-Line-Segment Coal Supply Curves

Coal Type	Price - \$/ton	Quantity - 10^6 tons/yr.
ELC	10.00	0
	16.20	230
	21.60	660
	33.10	1100
	107.00	1155
EHC	7.70	0
	16.60	150
	20.40	460
	33.10	810
	107.00	857
MHC	6.50	0
	8.90	125
	15.00	160
	19.60	960
	31.00	1450
	94.70	1483
WLC	5.50	0
	9.20	450
	19.30	2700
	28.50	3850

sulfur and Btu contents given in Table 2 were selected as being typical values for the four coal types.

Coal Beneficiation

Beneficiation, or "washing," is carried out at the mine mouth to improve coal quality by separating heavy sulfur-bearing and ash-producing inorganic minerals from the lighter, burnable, organic portion of the coal. Raw coal is crushed and slurried in water, and the separation is carried out on jigs, tables, "spirals," air flotation units, or other apparatus. The final product is dried in a rotary drier and the discarded material is reburied in the mine. (U. S. Dept. of Commerce, 1975; Cavallaro et al, 1974; Deurbrouck, 1972.)

Different levels of treatment are possible with coal beneficiation. The coal may be crushed to a fine mesh size and passed through a multi-stage separation device to achieve a high level of cleaning, or it may be coarse-crushed and separated in a simple apparatus to obtain a low level of cleaning. The process assumed for the model is described in the literature as "Level 3," a medium level process (U. S. Dept. of Commerce, 1975). We assume that this process reduces the ash content to 40% of its original value (i.e., from 17% to 6.8%). Also, the Btu content per lb is increased by 13%. We assume that 1.25 tons of raw coal are required to produce one ton of beneficiated coal. Some fuel value is lost in the discarded material, and approximately 40 lb of coal and 0.4 gallons of fuel oil are burned as drier fuel per ton of product (Lyons, 1950). Capital cost for beneficiation is assumed to be $4.22 per ton

APPENDIX TABLE 2. Raw Coal Properties

Coal Type	% Sulfur	% Ash	Btu/lb.
ELC	1.4	17.	13000
EHC	3.0	17.	12000
MHC	3.0	17.	10800
WLC	0.4	17.	8400

APPENDIX TABLE 3. Beneficiated Coal Properties

Coal Type	% Sulfur	% Ash	Btu/lb.
ELB	1.19	6.8	14690
EHB	2.11	6.8	13560
MHB	2.11	6.8	12200
WLB	0.38	6.8	9490

per year capacity, and operating cost excluding energy costs is assumed to be \$0.52 per ton. A 20% per year capital charge is applied. (U. S. Dept. of Commerce, 1975.)

Coal contains the inorganic sulfur mineral pyrite (FeS), which can be mechanically separated and removed by beneficiation. It also contains organic sulfur compounds which cannot be removed by beneficiation. As a general rule, high sulfur coals contain pyrite and organic sulfurs in roughly equal proportions. In low sulfur coals nearly all sulfur is organically combined. For the model, sulfur removal percent was assumed to be a function of raw coal sulfur content:

$$(\text{Percent S removal}) = 11\ (\%\text{S})^{0.9}$$

Thus for 3% sulfur coal 30% removal is expected, but for 0.4% coal only 5% removal is expected by beneficiation. Tables 2 and 3 give the properties of the four representative coal types before and after beneficiation, respectively.

The economic justification for beneficiation of steam boiler coals may stem from different factors. For all coals in the model, ash disposal costs at the boiler are reduced by 60%. For high sulfur coals, sulfur removal is an important benefit. For low sulfur western coals which must be transported long distances, the reduction in weight per Btu is significant in the model.

Coal Transportation Costs

In the model coal is assumed to be mined and beneficiated in the three regions, Eastern, Midwestern, and Western, as described above.

Two coal consuming regions, Central and Eastern, are used in the model to prevent large quantities of western low sulfur coal from being shipped to the eastern electric power industry at an unrealistically low price. To avoid further addition of rows and increased computation times, the petroleum refining, chemical, and plastics industries are assumed to be located in the Central consuming region. Also, no provision is made for other special regions, such as the U. S. West coast.

The Central coal consuming region is assumed to consist of the portion of the country west of the Appalachian Mountains, including areas served by barge transport on the Mississippi and Ohio Rivers. The Eastern region consists of the easternmost tier of states.

Table 4 gives the coal transportation costs assumed for the model. These costs were estimated based on PIES cost data (Childress, 1976).

APPENDIX TABLE 4. Coal Transportation Costs per Ton

Coal Type	To Central Region	To Eastern Region
Eastern (ELC, EHC, ELB, EHB)	\$8	\$5
Midwestern (MHC, MHB)	\$4	\$8
Western (WLC, WLB)	\$10	\$20

APPENDIX II

REVISIONS TO OTHER COMPONENTS OF MODELLING SYSTEM

In the interim between the analyses reported in The Costs of Energy (Thompson et al. (eds.), 1977) and the analyses for GEAC reported here, a number of revisions and improvements have been made to the various components of the overall system. A wholly new supply model was developed for oil and gas and has been documented separately (Kim and Thompson, 1977). A price-sensitive coal supply model was adapted from the work of FEA as described in Appendix I. Additional changes to and substitutions in the linear programming industry model, the end product demand model, and the supply-demand-industry interface will be briefly outlined here.

Revisions to Industry Model

(1) Process vectors designed to represent the production of nylon (and its precursors) and low density polyethylene were added to the model. New vectors for polyvinyl chloride were developed from more recent data.

(2) Extensive revisions were made to the electric power industry component of the model, both in terms of structure and estimates of process parameters. Major revisions were made in the method of accounting for air emissions and the control thereof. New cost parameters were developed for air emissions control processes. However, the electricity generating unit process costs and heat rates were retained from the previous version of the model. As mentioned previously, the electric

power component was also separated into two regions so as to account properly for the generation cost impact of the differences in coal transportation costs.

(3) Coincident to the revisions to the electric power sector a new system of vectors was designed to more accurately represent the burning of coal and fuel oil, both in large power plant boilers and in the kind of smaller boilers likely to be used by the process industries. FORTRAN programs were developed to estimate boiler capital and operating costs, air and water emissions, and pollution control costs (precipitators and wet scrubbers) for the various types of boiler fuel. In the model, it is possible to burn eight types of coal, three grades of residual fuel oil, and two grades of distillate fuel oil.

Fuel burning in each industry was required to comply with a specified standard of allowable air emissions. Particulate control was required for any fuel with a non-trivial ash content. Additionally, each industry was required to mix fuels or employ stack scrubbers as necessary to achieve an average sulfur oxide emission standard. New source performance standards were specified as 1.2 lbs SO_2/MMBtu for coal and 0.8 lbs SO_2/MMBtu for oil. Because of the variance in old source emission standards, a standard twice that of the new source standard was imposed in all cases except the strict SO_2 standards Case 5 (in which old and new sources were regulated alike). The distinction between old and new sources for electric power was clear-cut since the industry model explicitly deals with old and new plants in that industry. Such detail is not modelled for the process industries, however, and a further approximation was required. All coal-fired boilers were assumed to be new sources since the industries modelled do not currently use a great amount of coal as boiler fuel. An estimate of the mix of old and new oil-fired boilers is virtually impossible to obtain, however, so a simple composite standard of 1.5 times the new source standard was applied to roughly capture the effect of an unknown mix.

Finally, the end product demands for coal and fuel oils supplied by the industry model (as opposed to consumed by it) were required on the average to meet the new source standard without sulfur control. This is appropriate for residential and commercial demands since those establishments are generally of insufficient scale to install stack gas scrubbers. It is not completely appropriate for exogenous industrial demand, but the technique does indirectly account for the costs of sulfur control in non-modelled industries as the premium on the price of clean fuel supplied to those industries is determined by the cost of emission control on dirtier fuels as explicitly and accountably included in the industry model. By a similar logic, the costs of particulate control on these "sold" fuels is included in the objective function in order to prevent the occurrence of a cheap "out" for fuels with a high ash content.

(4) New estimates were made of the existing capacities of the different kinds of fossil-fueled electric power plants. Data published by the National Electric Reliability Council (1975) were employed, as that provided by the Federal Power Commission does not disaggregate steam generation among the various fossil fuel types. Unfortunately, the NERC

regional disaggregation did not completely correspond to the regionalization used in the model (which is based on FEA regions which are based on FPC regions). Accordingly, adjustments based on our experience were made for two NERC regions which overlap FPC regions.

(5) Production levels specified for the numerous products included in the industry model were all re-estimated on the basis of the most current data available. Such a re-estimate was believed important in order to account for the rather abrupt decline in refinery and chemical production following late 1973. The primary source for these estimates was the Chemical Engineer's Handbook which had largely complete data for 1974 and partial or projected data for 1975. The estimated 1975 production levels were then extrapolated to 1985 on the basis of assumed trends in population and income growth.

(6) Cost coefficients in the industry model were inflated to a 1975 price level on the basis of industry-specific components of the Chemical Engineering Plant Cost Index and the Marshall and Stevens Equipment Cost Index.

New End Product Demand Model

Price-sensitive demands for coal, electricity, distillate and residual fuel oils, natural gas, LPG, gasoline, kerosene, and jet-grade naphtha were determined for the model by an adaptation of the energy demand model employed by FEA in the PIES methodology (FEA, 1976). The model is a constant elasticity approximation of the larger, dynamic FEA energy model. According to FEA, any such approximation corresponds to (is calculated at) a particular solution to the PIES model; the only elasticity matrix for which complete documentation was available was that for the \$13 Reference Scenario in the 1976 Energy Outlook. The elasticities and base demands drawn from this scenario involve judgmental considerations, but these judgments were unavoidable in light of the available matrix are disaggregated regionally by FEA. The product demands for these regions were grouped to provide base demands for the two gross regions used in the analysis reported here. That portion of demand expected to be accounted for by industries in the LP model was subtracted to avoid double counting. The elasticities are appropriately weighted averages of regional elasticities. Since neither the regional elasticities nor the weighting factors were available, it was necessary to employ the same elasticity matrix for the two regions. Region-specific base prices are documented, and region-specific demands were used to derive average weighted base prices for each of the two regions. Given these base prices and demands and the matrix of own- and cross-price elasticities, "new" demands could be calculated corresponding to prices implicit in the scenarios modelled here. For coal and electricity, demands for the east and central regions were specified separately to the model. For all other products, demands for the two regions were added together to yield a single national demand. (The alternative would have been doubling the size of the industry model.)

<u>Modifications to Interface Technique</u>

In previous analyses, the prices input to the demand model were calculated directly from the prices of crude oil and natural gas by a formula external to the industry model. For the analyses here, the more appropriate sophistication was applied; that is, the prices input to the demand model were the shadow prices calculated by the industry model for the provision of the different fuel products. This meant that the criteria for convergence had to consider the equivalence of input and shadow prices for the basic fuels (crude oil, natural gas, and three types of coal) <u>and</u> the equivalence of the shadow prices on the several energy products from one iteration to the next (i.e., the shadow prices from iteration i were the input to the demand model for iteration i + 1, and the demands thus calculated were appropriate only if the shadow prices for iteration i + 1 were similar to those for iteration i). (Needless to say, this significantly complicated the procedure.) In practice, the equivalence of input and shadow prices for the basic fuels was the primary concern, and tolerances on equivalence of end product shadow prices often had to be rather loose because of corner-point phenomena in the LP solution. (Most tended, however, to be within 5 or 10 cents.)