Final Report

on the

PROVISION OF ELECTRIC POWER IN TEXAS: KEY ISSUES AND UNCERTAINTIES

VOLUME I

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PREFACE

The present project is prepared to present the major issues and uncertainties surrounding future electric power generation for Texas between 1976 and 2000. The study is prepared for the Forecasting and Policy Analysis Division of the Governor's Energy Advisory Council under Contract No. IAC-76-77 (1148) by the Center for Energy Studies at the University of Texas at Austin. The two major areas covered by the study include the economic and environmental impacts on Texas of the future electric power generation alternatives.

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CHAPTER 1

INTRODUCTION AND OVERVIEW

1.1 Introduction

The electric utilities in the state of Texas, form an extremely important basis for modern life for the citizens and industry of the state. They are the keystone for such essential services as telephone and telegraph communication, radio and television, heating and air conditioning, and provide a basic input for essential industrial processes such as the production of aluminum.

The process of supplying electricity can be conveniently divided into the three functional categories of generation, transmission, and distribution. Generation of electrical energy is accomplished in steam generating electrical plants by transforming the heat derived from fossil fuels and nuclear energy into electrical energy. Hydroelectric plants use turbines to directly transform the energy in falling water into electrical energy. The transmission system transports the electricity generated in such facilities over high voltage transmission lines to load centers from which it is delivered over the distribution system to final consumers.

There are presently 29 separate companies in the state of Texas which generate electric power. Twelve of these are investor-owned and 17 are owned or operated by municipal corporations or other public entities. The present electric generating capacity in Texas is about 38,000 mw(e), the largest of any state in the country.

The vast abundance of low cost natural gas in the post World War II period in the state of Texas made this fuel attractive for generation of electricity and provided a favorable environment for the expansion of energy-intensive industrial processing. Electricity was generated in the state almost exclusively by burning natural gas until the early 1970's, when the characteristics of the natural gas market began to change markedly. These sudden changes were partially in response to the price regulation policies promulgated by the Federal Power Commission, and also because the readily accessible natural gas reserves were becoming depleted. These changes have led to a complicated set of forces dominating the behavior of the natural gas markets. The result of these forces have been the promulgation of state and federal policies to discourage use of natural gas as a boiler fuel. Consequently, the electric utilities are faced with the need to convert to alternative fuels if they are to assure provision of electricity in the future. The most readily identified alternatives at least for the next 10 to 20 years are lignite, coal, oil, and nuclear fuels.

Each of these alternatives has potential risks and uncertainties associated with its use. Among these uncertainties are the extent and producibility of the basic resources, the capability for transport and the dependability of access to these fuels, the air, water, land usage, and other environmental effects of utilizing the alternatives. An additional factor is the posture of various state and federal regulatory agencies and legislative bodies underlying the business environment in the energy sectors.

This study represents an attempt to assemble and weigh the uncertainties and assess the economic and environmental impacts of various strategies the electric utility sector may develop. To do this the study team has investigated numerous sources of data, balanced conflicting claims and assertions, and considered possible future trends that might evolve as a result of increasing electricity requirements in the state of Texas. This report presents the findings of this effort.

1.2 Structure of the Study

The methodology of this study involved investigations in four areas related to electric power growth in Texas. Figure 1.1 is a broad overview of the methodological framework that was used. The circles represent areas of assessment which involved expert analysis, literature surveys, and personal communications from industry representatives. The rectangle represents the mathematical model which was used to obtain forecasts on electricity supply.

The following are four major components of the study:

a. Plant Economics and Operation Assessment:

The securement of best estimates of future economic and operational characteristics of the alternative plant types was the thrust of this part of the study. Plant capital cost estimates were obtained by direct communication with most of the major electric utilities in Texas. Operational data such as capacity factors, heat rates, and operation and maintenance costs were obtained from electric utility statistics and other publications. This information was utilized as basic input to the electricity supply/cost analysis of alternative forms of electricity generation available in the state of Texas in the future. Only currently available technology was considered. The findings of the comparative plant economic assessment can be found in Chapter 3.

b. Electricity Supply/Cost Analysis:

A Texas Electricity Model was used to produce supply configurations and generation mixes for the alternative demand growth and supply assumptions. The model also provided numbers on average electricity prices and aggregate capital and fuel requirements. Inputs into the model were plant costs, operational quantities such as heat rates and capacity factors, operation and maintenance costs, and fuel costs.

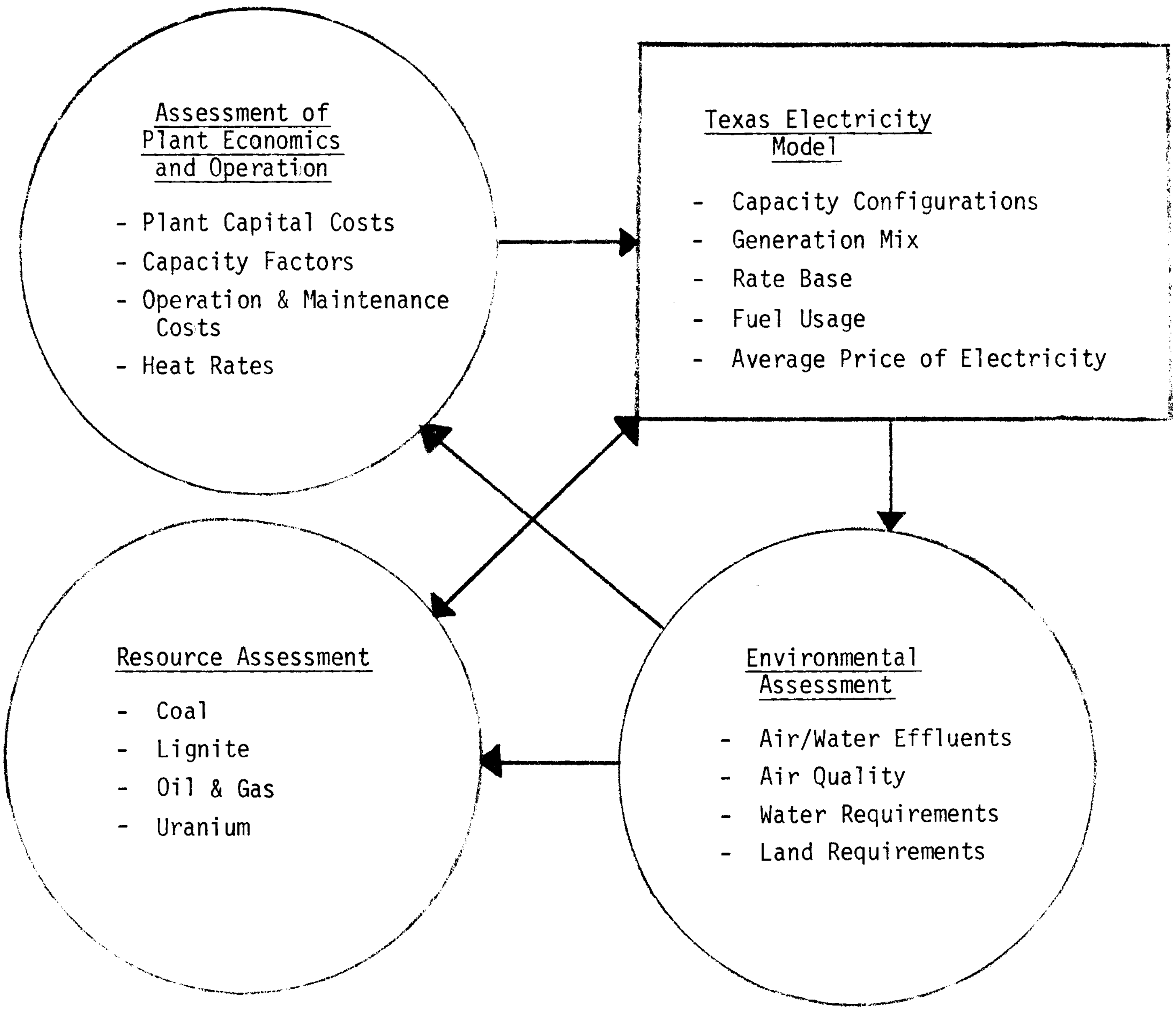

Figure 1.1

METHODOLOGICAL FRAMEWORK

Some of the fuel cost estimates were provided by the GEAC and the rest were obtained from resource assessment studies. The model is described in detail in Appendix A.

c. Resource Assessment

The resource assessment part of the study involved an economic assessment of fuel availability. The supply prospects for coal, lignite, and uranium were studied at length to determine as closely as possible the resource, production, transportation, and conversion properties of these fuels. Substantial uncertainty still remains in the outlook for these fuels because of possible regulatory restrictions. Several of the case studies reported later in this document deal with the impacts of alternative developments for these fuels. The results of these analyses are reported in section 3.2 for coal and lignite, and in 3.3 for uranium. The projected costs for oil and gas were obtained from the Texas Governor's Energy Advisory Council.

d. Environmental Impact Assessment:

The environmental impacts have been estimated for the alternative energy supply and demand configurations. Statewide changes in levels of air and water effluents, air quality, and water and land requirements have been computed for each of the cases. The effects of the air quality changes on public health, agricultural productivity, and other environmentally related areas were assessed. The capital and operating costs of environmental control equipment required to comply with alternative regulations were also evaluated. These estimates were used as inputs to the electricity model as a component of plant costs where varying air and water quality standards were hypothesized.

1.3 Key Findings

Several important considerations are identified and reported throughout the text of this document. Following are the major findings:

1. The use of natural gas for electricity generation will decline in the future. The Railroad Commission has adopted an order forcing consumption of gas as a boiler fuel to decline by at least 25% by 1985. If economic forces prevail, it is likely that natural gas consumption by 1985 will be substantially less than even what the Railroad Commission has ordered, but this will be possible only if the regulation of electric utilities is such that expansion of alternative fuel burning capability is permitted. Figure 1.2 shows the possible range of gas consumption.
2. Additional capacity requirements in the state of Texas between now and the year 2000 are expected to range between 75 and 115 Gw(e), 20 Gw(e) of which would be replacement for existing natural gas-fired capability.
3. The extent to which oil is used as a source of generation in the future is highly dependent upon the stringency of future ambient air quality and source emissions standards. The future use of oil on a large-scale basis may be dependent on the implementation of major oil desulfurization at petroleum refineries in Texas.
4. The future use of coal and lignite as fuels for electric power generation may be discouraged if air pollution standards are set at overly stringent levels unless suitable environmental control technologies are developed. Otherwise, nuclear

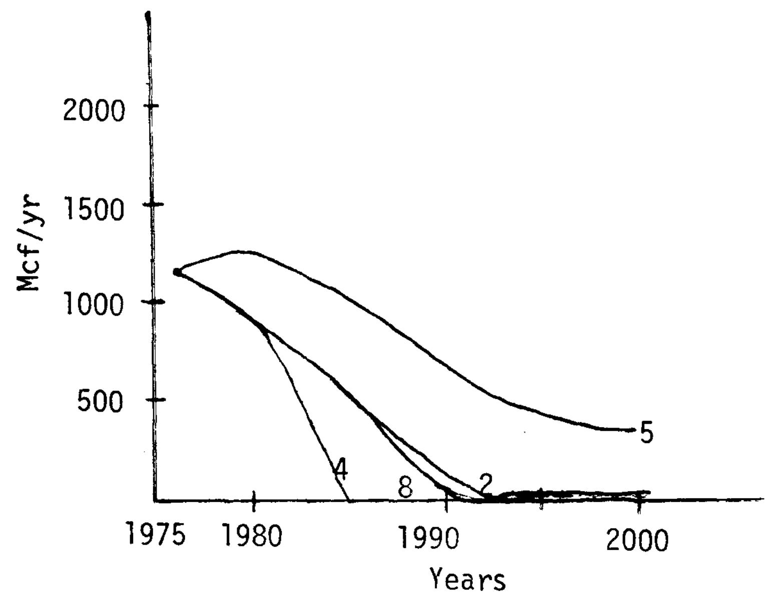

Figure 1.2

PROJECTED RANGE OF GAS CONSUMPTION

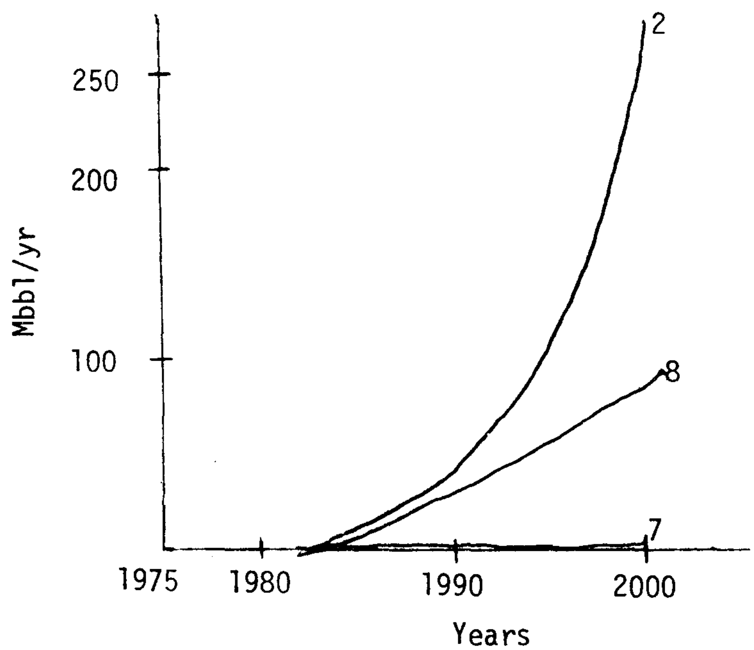

Figure 1.3

PROJECTED RANGE OF OIL CONSUMPTION

power and fuel oil combustion would be the only suitable alternative energy sources.

5. Expansion of oil use could be constrained by existing federal legislation, the Energy Supply and Environmental Coordination Act (ESECA) of 1974. If oil use is constrained through vigorous enforcement of this legislation and environmental considerations force the delay or cancellation of additional coal and lignite plants, the reliability of electricity supply could be in jeopardy as early as the late 1970s. The possible range of future oil consumption is shown in Figure 1.3.
6. Presently known U.S. uranium reserves are capable of supporting lifetime operation of about 300 Gw(e) nuclear capacity using current technology. At present slightly over 200 Gw(e) capacity has been committed in the U.S., of which 9.9 Gw(e) are planned or committed in Texas.
7. If Texas utilities are successful at securing the fuel for 10% of the uncommitted available light water reactor capacity, Texas can be expected to achieve a maximum of about 20 Gw(e) installed nuclear capacity. (Sales of electricity in Texas are currently 7.7% of the nation's total.) Figure 1.4 brackets the use of uranium by electric utilities in Texas.
8. The indigenous lignite resource base falls between 10 and 11 billion tons in near-surface deposits. If all this lignite can be mined and used, it is capable of supporting about 75 to 80 Gw(e) of capacity in the state for 30 years. The state now has installed 2.3 Gw(e) of lignite-fired capacity

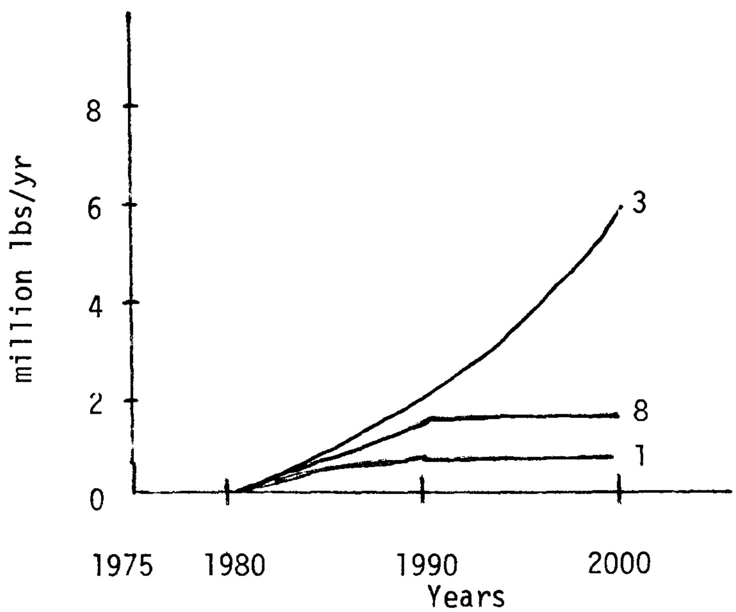

Figure 1.4

PROJECTED RANGE OF URANIUM USE

(all in North Texas) and plans for an additional 9.2 Gw(e) for installation by 1985. Extensive use of deep-basin Texas lignite would require the implementation of in situ gasification technology.

9. South Texas lignites, which comprise about 11% of the state's total resources, frequently have high levels of ash, moisture, sulfur, and trace elements such as toxic metals and uranium. Use of this portion of the state's lignite resources could result in significant environmental hazards to adjacent downwind receptors if burned without the use of best available stack gas control technologies. The extensive use of air pollution abatement technology capable of cleaning up the stack gases would necessitate by-product recovery of sulfuric acid, fly ash, uranium, and trace metals in order to become both cost and environmentally effective.

10. The state's utilities will have to depend upon out-of-state low sulfur coal for at least a portion of the state's future fuel needs. Out-of-state coal requirements range between 40 to 100 million tons per year by the year 2000 depending upon the economics of lignite use, the extent to which the state's utilities adopt nuclear technologies, and the air quality standards that prevail.

11. The out-of-state coal will likely be supplied from New Mexico, Wyoming, and the upper Great Plains states. Rail capacities appear adequate to handle traffic for the next decade, but the large quantities of coal needed by Texas and other southwestern states could tax the transport capabilities if

maintenance, planning, and expansion of the rail system is not anticipated. Figure 1.5 shows the range of future coal consumption by electric utilities in Texas.

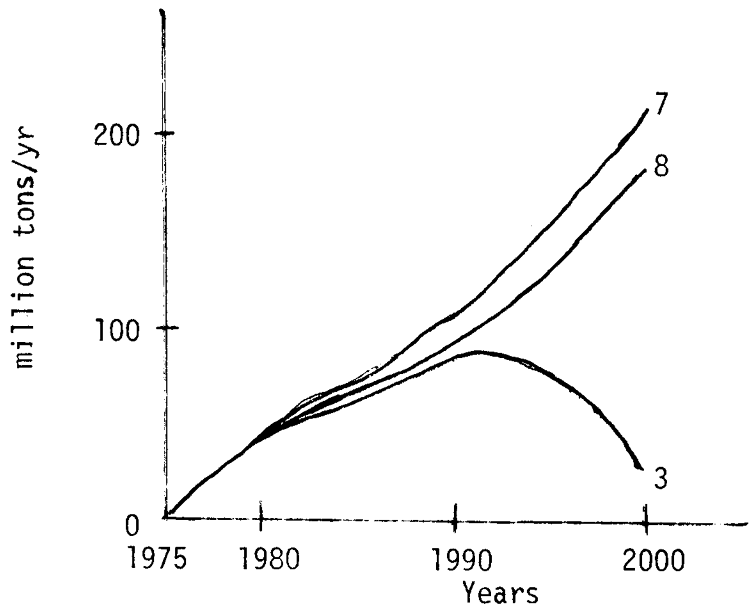

Figure 1.5

PROJECTED RANGE OF COAL CONSUMPTION

12. The future cost of delivered electrical energy in Texas will continue to rise on the average in the future, but at a rate only slightly greater than the overall rate of inflation. The most significant rate increases will occur generally for those utilities currently using low cost natural gas. Consumers in the service areas of those utilities currently using high cost natural gas and/or oil (e.g., Austin, San Antonio, and Corpus Christi) can expect lesser rate increases in the future than the state average if utilities serving these areas are allowed to bring nuclear,

coal, and lignite alternatives into their fuel mix. Figures 1.6 and 1.7 bracket future electricity prices in Texas.

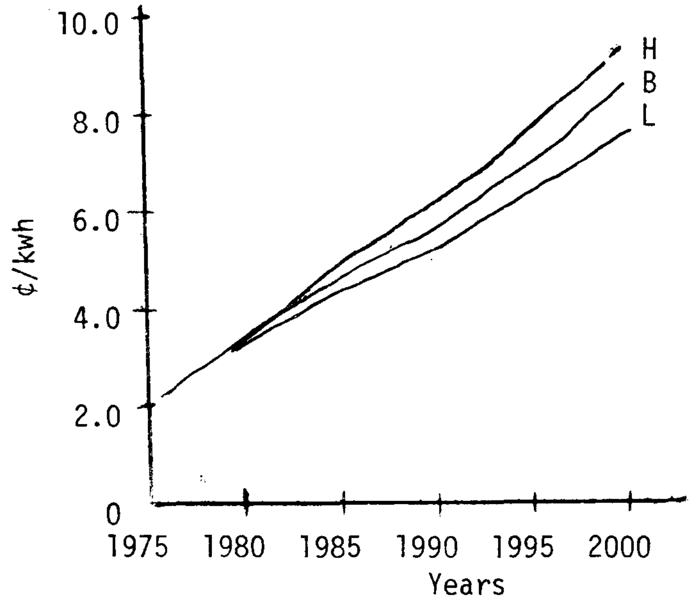

Figure 1.6

ELECTRICITY PRICES FOR ALTERNATIVE GROWTH ASSUMPTIONS

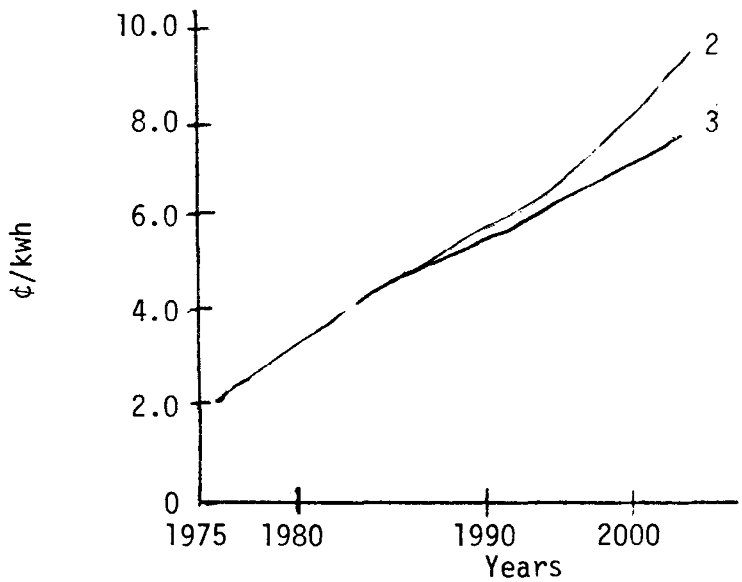

Figure 1.7

ELECTRICITY PRICES FOR ALTERNATIVE ENVIRONMENTAL POLICY ASSUMPTIONS

13. Particular problems surround the siting of power plants in Texas because of limitations in water availability, especially in West Texas. The problem is accentuated because most power plants in Texas must be located in relatively limited areas as a result of constraints for transportation, fuel resource availability, water availability, and proximity to load centers. There may not be sufficient water resources available if all power plants in Texas are sited at inland locations to utilize fresh water. Shortfalls in water resource availability of up to 300,000 acre-feet per year (15 times the capacity of Lake Austin) may result from extensive nuclear power plant development and as much as 200,000 acre-feet per year (10 times the capacity of Lake Austin) for extensive lignite development.

14. Major capital and operating costs will be required for waste heat dissipation at electric power plants between 1976 and 2000. Extensive use of nuclear power at inland locations will result in capital expenditures of $1.8 to $1.9 billion with comparable values of $1.3 to $1.4 billion with extensive coastal location. These values are reduced to $1.4 to $1.6 billion for all inland locations with major coal or lignite usage. Annual operating costs by 2000 will range between $1.0 and $1.3 billion per year for all inland fresh-water locations, and $0.8 to $1.0 billion per year for extensive coastal siting.

15. Potential impacts upon water resource availability can be

minimized by limiting the use of throwaway sulfur oxides scrubbing on lignite plants and by coastal siting of coal or nuclear plants. Coastal siting will permit use of salt water as the waste heat dissipation medium by means of either once-through cooling, cooling ponds, or cooling towers. The extensive use of saltwater cooling at coastal sites is feasible for western coal and nuclear power plants because of the unfavorable long distance transportation economics.

16. Significant increases in air pollutant generation will result from the increased use of coal and lignite for electric power generation in Texas as natural gas is phased out as a boiler fuel. The use of coal and lignite for electricity generation will significantly increase emissions of particulate matter, sulfur dioxide, and nitrogen oxides to the air in Texas. Coastal siting of coal-fired power plants will act to accentuate photochemical air pollution formation at inland locations from oxides emissions resulting in ozone and sulfate aerosol formation. By the year 2000, the rate of emissions of particulate matter and sulfur oxides could increase to more than 10 times their current values. Trace metal and organic emissions could multiply several-fold in the same period. Total solid wastes produced as a by-product of electricity generation could increase to 15 times the current value. The extent of these increased emissions will be minimized

with conversion to nuclear power and maximized with the use of native Texas lignites.

17. Major capital and operating cost expenditures will be required by the electric power industry between 1976 and 2000 for air pollution control equipment. Capital expenditures of $5 to $8 billion will be required for air pollution controls by the year 2000, depending on the type and stringency of regulations. Pollution control equipment of lignite plants will require the greatest capital investment, with 70 to 80% of this cost needed for sulfur oxides controls. Nitrogen oxides controls may need to be implemented on coal-fired power plants located in or near coastal areas. Total operating costs of $1 to $2 billion per year will be required by the year 2000 for this air pollution control equipment.

18. Financing this amount of air pollution control and waste heat dissipation equipment could be a significant problem for the utilities involved. Cumulative capital expenditures by the electric utilities over the period 1976 to 2000 will have to be about $140 billion when excluding environmental control equipment. The higher capital and operating costs due to the pollution control equipment will translate to about a 10% additional increase in electricity prices.

19. If load management policies were successfully implemented, the need for new capacity in the future would be reduced. An improvement in the average load factor in Texas by about 20 percentage points (i.e., from 48% to 68%) would result

in a 20 to 25% reduction in the capacity requirements by the year 2000. Reduction of new capacity additions would prolong the use of existing capacity, mainly natural gas plants. The short- and medium-term result of load management would therefore be a continued dependence on high cost natural gas and oil in existing plants. The price of electricity would therefore be higher than what it would be without load management under existing electricity pricing procedures, until a substantial portion of this existing gas-burning capacity were retired or converted. The effects of load management are not what they are generally believed to be, at least in the short run. Successful implementation can lower capital-intensive capacity requirements but substantially increase the cost of electricity.

20. The state of Texas may want to encourage the recovery, reuse, and resale of by-products from coal and lignite combustion such as sulfur or sulfuric acid, ash materials, and nitrogen compounds for chemicals, fertilizers, and building materials. To be cost effective, common siting of electric power generation facilities with synthetic fuels production facilities, uranium and metals recovery, chemicals manufacture, and petrochemical operations may be necessary to facilitate the by-products recovery operations.

21. Present ambient air quality standards for particulate matter need to be modified to facilitate the siting of future coal

and lignite-fired power plants in Texas. Rigid interpretation of existing federal secondary particulate standards would preclude the siting of any coal or lignite generating capacity in any region of Texas because of high background natural dust levels, while compliance with primary standards would allow siting in only a few locations. Ambient particulate standards differentiate between natural and manmade activities by incorporating particle size distribution and chemical composition variations into the standards. Ambient particulate standards need to be established for specific constituents (such as sulfate and nitrate aerosols, trace metals and trace organics) tied to power plant operations.

1.4 Key Regulatory Considerations

The future supply of electric energy to consumers in the state of Texas has present several potential pitfalls. The regulatory institutions and consumer groups, although historically not significant forces in the state's electricity picture, may become more activist in the future as a direct result of the transition being experienced by the electric utilities. Aside from the uncertainty in future growth of electric demand and the problems this poses on the responsibility of electricity suppliers to maintain reliable electric service, a number of potential constraints on electricity supply could become reality. Among these are problems of air quality, water availability, and dependable access to fuel resources. Each of these problems has direct implications for one or more state agencies in their dual roles of protecting the public interest while advancing a climate where low cost reliable electric energy supply is possible in the future.

The newest and possibly the most powerful force in future electricity developments is the Texas Public Utilities Commission. This commission is already faced with a dilemma, the resolution of which could be the most significant event in the future outlook for electricity supply in the state of Texas. Among other things, this commission is faced with the responsibility of assuring fair and equitable rates for electricity to consumers of electric energy. The dilemma is that there is a set of short- vs. long-term interests which this commission must try to balance. The dilemma occurs because of the necessity for the utilities to effect a transition from gas and oil consumption to coal, lignite, and/or nuclear resources. The utilities commission must balance the desire for low rates in the short run with the knowledge that electric utilities must acquire the financial capability to purchase and install generating equipment that consumes nonpetroleum fuel resources in the long run. This is further complicated by the need for accelerated depreciation of existing gas/oil-fired capability. If the short-term interests dominate, consumers may enjoy slightly lower rates in the short run, but be faced with the prospect of future supply interruptions and long term dependence on our most precious and costly fuel resources. If a balance is achieved so that a transition can be effected, other problems are encountered.

An expansion of coal and lignite use will be accompanied by significent increases in emissions to the air even when currently best available control technologies are a part of the plant's construction. The Texas Air Control Board has the potential by strict interpretation of the EPA's and state's emissions and air quality standards to interfere with the timely adoption of technology that could be powered by these fuels. This problem could come about through delays in issuance of the permits necessary for plant operation, through discouragement in adoption of the nonpetroleum utilizing technology by requiring excessive pollution abatement measures be taken, or by excessively stringent interpretation of secondary ambient air quality standards or nonsignificant deterioration regulations. The consensus of consumer and public interest on the economic vs. environmental tradeoffs is most difficult, if not impossible, to ascertain. Meanwhile, the Texas Air Control Board must try to protect the public welfare when only the most vocal opinions are presented.

Water availability is a potential problem underlying all supply scenarios presented simply because water resources are fixed, and additional electricity generation will require additional water. Under all alternative fuel scenarios this is true, but the problem is severest under the assumptions of high nuclear growth with inland siting. The Water Development Board, the Water Rights Commission, and the Water Quality Board are all aware of the potential demand upon this resource from electric utilities as well as from agricultural, municipal, and other industrial users. Water conservation cooling technologies such as wet-dry cooling towers and multiuse reservoirs as cooling lakes are ways of decreasing water requirements for nuclear electricity generation, but in the long run offshore siting on the Gulf of Mexico may be the only alternative. Electric utilities have the advantage that they can use salt water for cooling, whereas in municipal and agricultural uses there is no alternative but to use fresh water.

Policies of the Texas Railroad Commission will have direct bearing on the viability of the coal option to electric utilities in the future. The Railroad Commission Order to gas utilities (Docket No. 600) dictates that electric utilities must decrease their consumption of natural gas by 25% by the year 1985 and provides the most tangible direct evidence that the need for transition exists. The utilities must seriously consider out-of-state coal for burning in both new plants and possibly through conversion to synthetic natural gas or to methanol as a substitute fuel in gas plants. In the long run, unless slurry pipelines obtain the right of eminent domain, there are likely to be large demands placed upon the rail transport system by the growing coal markets in the state. The policies of the Interstate Commerce Commission in establishment of freight rates will have direct influence upon the competitive position of coal. The large-scale development in Texas of a coal conversion industry producing synthetic liquid and gaseous fuels will intensify these demands on the railroad system.

The indigenous lignite resource is a large but uncertain quantity as a future fuel for electricity generation. The prime North Texas lignite resources are already committed for electric power generation by Texas Utilities Company. These holdings are capable of supplying about 10,000 Mw capacity. The use of South Texas lignite may pose serious environmental hazards, as is documented in this report, making much of this resource potentially unusable unless highly efficient emission controls with uranium and metals recovery are employed. Even if ways of controlling the emissions from the South Texas lignite are developed, the timely acquisition of minable quantities is a problem due to the dispersion of mineral rights among numerous land owners. There may be a role here for the Governor's Energy Advisory Council, to establish through an interagency task force, the potential and limits of this resource and help remove the uncertainties clouding its outlook.

The future of nuclear power is enhanced by the air quality problems that accompany coal and lignite use, but nuclear has problems of its own. Given the present, and admittedly limited knowledge, on uranium resources, it is not possible to count on nuclear power as the limitless resource it was once thought to be. At the same time, vocal public reaction from various interest groups and continuing slow progress on the part of the federal government in providing an environment for closure of the fuel cycle manifest a climate of concern about this technology. It is a fact that nuclear power plants are competitive and, given our best information, will continue to be a competitive source of electric energy generation. But, unless the long-term uncertainty in fuel availability is reduced and the intermediate problems of fuel cycle closure are resolved nuclear power cannot be expected to contribute more than a portion of the state's future electrical needs.

Finally, though given scant attention in this report due to its advanced nature, Gulf Coast geopressured geothermal may be able to contribute to the state's future electrical needs, but probably not until the 1990's. Unless and until the state takes the lead in determining the potential of this resource, it will likely remain a topic for academic research.

The culmination of these considerations is an environment in which the provision of low cost and reliable electricity is difficult, but not impossible. In a highly uncertain environment a mixed portfolio of investment is the best strategy, and this adage seems to apply here. Under most scenarios analyzed in this report we do not project continuing rapid increases in costs of electricity supply such as have been seen in the past three years. However, vigorous environmental protection policies could reduce the possible alternatives available making the state dependent upon resources which may become costlier in the future. The correlation between low cost energy and economic welfare has been amply demonstrated by the recession of 1974-1975 following the OPEC oil embargo and the subsequent increase in oil prices. If faced with a similar prospect in the future, especially in the electric utility sector, serious measures might have to be taken. The imposition of load management programs is demonstrated in this report to offer little short-term benefit unless short-term capacity shortages are imminent. In the long run load management, through the securement of flatter load shapes, does reduce the amount of new capacity needed and the associated number of new sites, but places greater dependence upon existing capability.

Rates for electricity must be allowed so that utilities can afford to reduce their high dependence on natural gas at present, and the costs of environmental protection should be passed on to the consumer. If such costs should begin to burden the economic growth potential of the state, however, the state may have to reexamine its position, whether that position is explicit or implicit, on what is best for the welfare of its citizens. It will also be necessary to develop methods for reuse of by-product residuals from electric power generation to minimize potential costs of environmental control technologies, to enhance common siting of energy production and chemical processing operations, and to encourage use of these residuals for agriculture or construction.

CHAPTER 2

HISTORICAL BACKGROUND AND FUTURE ALTERNATIVES

2.1 Historical Background

The electric utilities of Texas have historically enjoyed a position of prominence among the electric utilities of the nation. With easy access to clean and relatively inexpensive natural gas, the Texas utilities have not incurred the scrutiny of environmentalist groups as the electric industry has in many other regions of the country. The cheap natural gas as fuel served to maintain low costs of electricity conversion which in turn helped to sustain a relatively apathetic but increasingly dependent group of consumers. A moderate climate, combined with higher construction labor productivity, has kept the costs of new plant construction well below the national average. In addition, sound planning and good management have served to make at least the privately owned sector of Texas electric utilities one of the most financially secure in the nation.

Historical Trends in Electric Sales

Sales of electric energy in the state of Texas have grown from 34.8 billion kilowatt hours in 1960 to 120.8 billion kilowatt hours in 1973. Historical trends in sales are tabulated in Table 2.1

The fastest growing sector has been the residential sector, followed closely by the commercial and industrial sectors. The growth demand in all three categories has been substantially higher than the corresponding national averages, in part reflecting higher growth in both industrial output and population than the national average over the

TABLE 2.1

SALES OF ELECTRIC ENERGY IN TEXAS
(billions of kilowatt hours)

	Residential	Commercial	Industrial	Other	Total
1960	9.8	8.5	14.5	1.94	34.8
1965	16.6	14.9	23.4	2.31	57.1
1970	28.9	23.1	40.1	3.12	95.2
1971	31.3	24.8	42.7	3.35	102.1
1972	35.1	27.6	46.6	3.61	112.8
1973	37.1	29.7	50.3	3.62	120.8
1974	37.8	30.1	52.4	3.66	124.1
1960 - 1974 Average Growth Rate	10%	9.5%	9.6%	4.6%	9.5%
1960 - 1974 National Average Growth Rate	8%	8.4%	5.2%	6.3%	6.7%

Source: Edison Electric Institute, New York, Statistical Yearbook of the Electric Utility Industry. Table 22S

TABLE 2.2

AVERAGE PRICES PAID FOR ELECTRICITY IN TEXAS
(cents per kilowatt-hour)*

	Residential	Commercial	Industrial	Other	All Categories
1960	2.57 (2.47)	2.15 (2.47)	.99 (.96)	1.75 (1.92)	1.75 (1.69)
1965	2.30 (2.25)	1.9 (2.13)	.88 (.90)	1.28 (1.71)	1.56 (1.59)
1970	2.04 (2.10)	1.72 (2.01)	.80 (.95)	1.34 (1.59)	1.42 (1.58)
1971	2.04 (2.19)	1.73 (2.1)	.80 (1.03)	1.35 (1.67)	1.42 (1.67)
1972	2.07 (2.29)	1.77 (2.22)	.84 (1.09)	1.41 (1.8)	1.47 (1.77)
1973	2.30 (2.38)	1.8 (2.30)	.92 (1.17)	1.42 (1.92)	1.51 (1.86)
1974	2.41 (2.83)	2.07 (2.85)	1.16 (1.55)	1.67 (2.44)	1.78 (2.30)

*National Averages given in parentheses

Source: Edison Electric Institute. Statistical Yearbook of the Electric Utility Industry. Tables 22S, 36S.

historical period, as well as relatively low costs of electricity. The average cost of electricity to Texas consumers has been below the national average since 1965, as shown in Table 2.2. This factor combined with the favorable climate and overall business environment in the state has resulted in a rapidly growing economy, population, and electricity sales market.

Generation Capability

Installed capacity in the state has grown much like the historical pattern of sales. Total installed capacity grew at an average rate of 9.7% per year in the state compared to growth in sales of 9.5% per year. Almost all new capacity additions over the 1960 to 1975 time period were in the conventional steam category, the bulk of these burning natural gas and/or oil.

Fuels Consumption for Generation

Texas electric utilities have been almost exclusively dependent upon natural gas as a source of energy for electricity generation. This dependence began shortly after World War II when natural gas was nothing more than a by-product of oil production. In these early days natural gas cost as low as 3¢/million Btu, only about 1.5% of the present cost of oil. With a plentiful supply of natural gas available as a by-product from the growing oil business, the electric utilities became very dependent on it (see Table 2.4). Between 1960 and 1970 the consumption of natural gas by the electric utility sector grew from 352 million mcf/year to 1342 million mcf/year, representing 14.3% of Texas production and 8.8% of the nation's consumption of this commodity by the end of 1970.

TABLE 2.3

GENERATION CAPACITY IN TEXAS
(in Megawatts)

	Conventional Steam	Hydro	Nuclear	Other	Total
1960	9452	390	0	212	10,054
1965	15102	437	0	226	15,765
1970	24522	517	0	239	25,278
1971	27504	517	0	238	28,259
1972	31206	517	0	239	31,962
1973	33199	517	0	249	33,965
1974	36814	517	0	249	37,580
1975	39432	517	0	249	40,198
1960 - 1975 Average Growth Rate	10%	1.9%	-	1.08%	9.7%
1960 - 1975 National Average Growth Rate	6.7%	4.8%	-	3.9%	6.3%

Source: Edison Electric Institute, New York. Statistical Yearbook of the electric utility industry. Table 3S.

TABLE 2.4

FUELS CONSUMED FOR ELECTRICITY PRODUCTION IN TEXAS

	NATURAL GAS		OIL		Coal and Lignite	
	(Million mcf)	(Trillion Btu's)	(Million bbls)	(Trillion Btu's)	(Million tons)	(Trillion Btu's)
1960	352	363	0.0528	0.32	0	0
1965	615	635	0.0376	0.23	0	0
1970	1060	1094	0.135	0.81	0	0
1971	NA	NA	NA	NA	NA	NA
1972	NA	NA	NA	NA	NA	NA
1973	1250	1290	5.93	35.6	4.86	87.5
1974	1342	1385	5.45	32.7	5.14	92.5

Source: Edison Electric Institute, New York. Statistical Yearbook of the Electric Utility Industry, various issues.

By the early 1970s, however, the characteristics of the natural gas market began to change markedly--partly in response to natural gas pricing policies promulgated by the Federal Power Commission, and partly because readily accessible natural gas reserves were simply becoming depleted. These changes have led to a most complicated set of forces dominating the behavior of the natural gas markets, and the electric utilities continue to be faced with a set of seemingly less favorable alternatives for assuring provision of electricity in the future than has been true in the past. These alternatives include lignite, oil, coal and nuclear.

By 1974 a small portion of generation was derived from the oil and lignite alternatives. In 1974, oil contributed to a little more than 2% of total generation, and lignite was used for a little more than 6% of total generation.

REGULATION IN THE ELECTRIC UTILITY SECTOR

There are currently 20 separate companies in the state of Texas that generate electric power. Twelve of these are investor-owned and 17 are owned or operated by municipal corporations or other public entities. Table 2.5 lists the larger of these operating companies, ranked by revenues earned in 1974.

Until September 1, 1976, the wholesale rates of only those utilities engaged in interstate commerce were regulated by individual municipalities in their respective service areas. The state legislature, effective September 1, 1976, established the Texas Public Utilities Commission and placed within its purview the jurisdiction of rates of the privately owned utility sector starting September 1, 1976. A municipally owned utility may continue to deal directly with its

TABLE 2.5

ELECTRIC UTILITY COMPANIES OPERATING IN TEXAS RANKED BY ANNUAL REVENUES IN 1974[a]

	COMPANY	REVENUES
1.	Houston Lighting & Power Company	$486,836,779
2.	Gulf States Utilities Company	348,842,252
3.	Texas Power & Light Company	316,067,688
4.	Texas Electric Service Company	234,413,480
5.	Central Power & Light Company	223,594,953
6.	Dallas Power & Light Company	180,558,820
7.	Southwestern Electric Power Company	145,760,225
8.	Southwestern Public Service Company	139,799,275
9.	San Antonio	87,467,106
10.	West Texas Utilities Company	65,773,177
11.	El Paso Electric Company	63,071,650
12.	Austin	58,903,403
13.	Community Public Service Company	55,605,782
14.	Lower Colorado River Authority	34,235,491
15.	Garland	15,276,483
16.	South Western Electric Service Company	11,570,845
17.	Lubbock	8,736,205
18.	Denton	7,219,244
19.	Bryan	6,932,207
20.	Floresville	1,700,392
21.	Robstown	1,650,814
22.	Weatherford	1,537,997
23.	Brenlam	1,293,291
24.	Cuero	958,672
25.	Brady	832,848
26.	Fredricksburg	736,306
27.	Gonzales	685,439
28.	Guadalupe-Blanco River Authority	612,256
29.	Brazos River Authority	295,440

[a]Source: Federal Power Commission, Statistics of Privately Owned Electric Utilities in the United States, 1974, and Statistics of Publicly Owned Utilities in the United States, 1974. Revenues in table are total company revenues, including out of state sales where applicable.

municipalities in the setting of rates, or after September 1, 1977 the municipality may vote to have the local utility come under the jurisdiction of the state Public Utility Commission.

Most of the major privately owned companies have not come under federal review because of the so-called Texas Interconnected System. This system, comprising an interconnection of the majority of the utilities of the state was not interconnected across state boundaries. However, the future status of the Texas Interconnected System is now undergoing intensive review by several regulatory authorities and courts. The Federal Power Commission has jurisdiction only over interstate wholesale sales of electric power.

Environmental Regulation in the Electric Utility Sector

Generation of electric power has historically required large amounts of cooling water and, depending on the fuel used, can result in the emission of large quantities of gaseous and particulate matter into the atmosphere. The state agencies most directly responsible for regulation of air quality and water usage are the Texas Air Control Board, the Texas Water Rights Commission, and the Texas Water Quality Board.

With the high dependence on natural gas as a boiler fuel in the past, degradation of air quality as a by-product of electricity generation has not been nearly as visible as it will be in the future when utilities adopt coal and lignite as large-scale sources of energy. To date, protection of air quality has been accomplished by emission standards rather than by ambient air quality standards. Further, these emission standards have been applied only to sulfur dioxide and particulate matter. That is, legal constraints are placed on the percentage of emitted gases that can be sulfur dioxide and particulate matter rather than on maximum concentrations at ground level in surrounding locations from the source. The Texas Air Control is responsible for monitoring and enforcement of these standards.

Because available water is scarce, the allocation of existing water supplies could become one of the biggest constraints on expansion of electrical output unless more water efficient utilization technologies become available or offshore siting becomes a possibility. The Texas Water Rights Commission is responsible for issuing permits for fresh water usage. At this time several rivers, including the Lower Colorado have available water allocated. The only way a utility can secure additional water from these rivers is to purchase the rights for water from existing owners. In addition the utilities must compete for additional water supplies with municipal and agricultural users, sometimes considered higher priority users. The Texas Water Development Board is responsible for planning future use of existing and proposed water supplies and the Water Quality Board is charged with enforcing the standards of water quality.

2.2 Alternatives for the Future

The combination of the necessity to switch to alternative fuels and the new regulatory environment in the state poses significant problems for the timely provision of electric energy to consumers in the state of Texas in the future. This study examines the economic and environmental consequences of the implementation of a range of alternatives available to supply the fuel requirements of electric utilities. Following are the dimensions of the evaluation.

1. Cost of electricity to consumers in Texas.

2. Fuel requirements of the electric utility sector under various assumptions of regulation/deregulation and environmental standards.
3. Capital requirements of electric utilities for constructing generation, transmission, and distribution equipment for scenarios.
4. Emission rates of various effluents to air and water.
5. Land and water requirements for the supply scenarios.

These areas of evaluation cover most of the material discussed in this report. However, other topics not mentioned above have been included wherever required in the report.

Electric utilities in Texas and in other states which have been highly dependent on natural gas have had to consider investment in alternative types of generating capacity. This change has posed a major problem. The uncertainties associated with the alternatives loom large, and therefore any decisions favoring one alternative over the other are susceptible to controversy.

In the absence of gas availability, electricity can be generated by the use of coal, lignite, oil, or nuclear fuel. The desired capacity and generation by each plant type are dictated by economic variables such as capital and operating costs, as well as by noneconomic externalities such as environmental and other regulatory policy restrictions. Many of the economic variables, such as fuel costs, are somewhat uncertain since they are dependent on noneconomic factors like price deregulation. Environmental and regulatory policies, too, are not easily predictable; an example being the nuclear referenda voted on by citizens of several states in 1976.

Because the future is dependent on many uncertain parameters, it is futile to claim that any forecasts are absolutely accurate. However, it is possible to determine with a fair degree of accuracy the economic and environmental impacts of a number of policy decisions given a set of probable growth scenarios. This study, therefore, is an attempt to delineate the economic and environmental effects of the implementation of a set of policy alternatives under different growth conditions.

A problem encountered in this study has been the handling of uncertainties inherent in the supply, demand, regulatory, and environmental areas. The difficulty is compounded by the fact that the four areas are closely interrelated, giving rise to complex interactions. More specifically, major uncertainties surround:

1. Changes in federal and/or state pricing or regulatory policies governing natural gas and oil contracts,
2. Availability of U_3O_8 for fueling nuclear power plants,
3. Air and water emission standards and therefore capital costs of pollution abatement equipment, ability to use lignite, etc.,
4. Transportation capability for transporting large quantities of western coal in case local lignite is not usable or available,
5. Inflation rates and hence future capital costs of electric power plants,
6. Future electricity demand growth rates,
7. Impacts of new technology,

8. Changes in resource costs of primary fuels as a result of the uncertainties mentioned above.

These uncertainties are dealt with first by constructing cases (scenarios) so as to encompass most of the probable range of outcomes, and second, when the probable outcomes are not exactly determinable, by using educated estimates or best guesses. Specifically, alternative policies on regulation of natural gas and oil prices, U_3O_8 availability, environmental standards, and electricity demand growth, are all covered by constructing supply and demand scenarios that directly portray alternative prospects for these quantities. Uncertainties in other areas such as plant and equipment capital costs, transportation capabilities, and inflation rate are dealt with by using best estimates.

The scenarios cover the two dimensions of supply and demand in the electric utility sector. In all, there are eight primary supply scenarios, made up of the base case and seven other cases, and three demand scenarios. The demand scenarios have been reported for the base case supply conditions only, In addition, there are three supplementary supply scenarios, one a regulated version of the base case and the remaining two depicting alternate source locations for fuel supplies in an alternative case. All scenarios are tabulated in Table 2.6.

The demand growth scenarios depict low, medium, and high growth in electricity demand in Texas. The low growth case has a yearly growth rate of 4%, the medium 5-1/2%, and the high 7%. The high growth scenario corresponds to demand projections available from ERCOT. However, resource availability constraints may substantially hamper a 7% growth rate and therefore, at the behest of those carrying out conservation

TABLE 2.6

SCENARIOS FOR FUTURE ELECTRIC POWER SUPPLY AND DEMAND IN TEXAS

SCENARIO	DEMAND FOR ELECTRICITY
Base Case (deregulated)	√
(regulated)	X
1 Nuclear Constrained	
1a - N. Texas Lignite	√
1b - S. Texas Lignite	0
1c - Coal	0
2 Medium Air Quality	X
3 High Air Quality	√
4 Gas Consumption - Zero by 1985	√
5 Load Management	X
6 Ground Level Standards	√
7 Constrained Supply Case	X

√ - Economic and environmental study

X - Only economic study

0 - Only environmental study

assessments, it was decided to include the low growth scenario. The medium growth scenario was selected as being the most likely, and is in fact a compromise between the high and low growth cases. Incidentally, the three growth rates are very close to those used by the FEA in their National Energy Outlook Study.

It is obvious from the above discussion that the demand growth cases are not constructed to depict specific policy or regulatory behavior, though, in a way, they are possible responses to alternative conservation legislation and various fuel supply situations. They could also be thought of as representing different estimates of responsiveness (i.e., elasticity) to changes in factors affecting growth. However, demand is not modeled as price responsive in this study; thus future electricity consumption is assumed to be an exogenous quantity strictly determined by the growth scenario used.

The supply scenarios, on the other hand, depict specific regulatory conditions or resource availability constraints. The base case represents a scenario that in our estimate best characterizes the future situation. The remaining supply scenarios depict the future of electric power in Texas under other supply assumptions.

2.3 Base Case

The base case supply scenarios contains the following assumptions:

a) Existing price regulations on natural gas continue, i.e., interstate prices are regulated and intrastate are not regulated

b) Oil prices remain regulated

c) Current air quality standards and best available wastewater emission standards

d) Nuclear generating capacity in Texas restricted to 20 Gw due to U_3O_8 supply constraint

e) No national boiler fuel restrictions

f) Railroad Commission of Texas Docket 600 restrictions applicable to gas-fueled generating plants in Texas

g) No technological breakthroughs in the time under consideration

Gas use by electric utilities in Texas will be substantially constrained by the Texas Railroad Commission order contained in Docket #600. However, in the absence of any federal rulings in this area it is assumed that there will be no nationally imposed restrictions on boiler fuel use. This assumption is not very critical because even without restrictions on natural gas use the economics of generating electric energy will discourage its use.

The base case analysis also assumes air quality standards can be met with current technology and best available wastewater emission standards. These assumptions affect the capital costs of generating plants and hence are included in the supply assumptions.

The base case also includes an assumption regarding nuclear fuel availability. We feel that if the current level of national uranium exploration is any indication of what is to come in the future (at least for the time horizon under consideration) it will not be possible to obtain uranium, naturally occurring and reprocessed, to fuel more than 100 Gw of nuclear capacity beyond that already committed in the U.S. Ten percent of this national capacity is assumed to be located in Texas, amounting to 10 Gw of nuclear capacity beyond what has been already committed (9.9 Gw) in Texas. This results in an upper bound of about 20 Gw for nuclear capacity in Texas in the time horizon of the study. Implicit in the above is the assumption that there will be no significant technological breakthroughs in this area in the next 25 years, at least not on a commercial scale.

The base case, as discussed above, assumes that the intrastate price of natural gas will remain unregulated as it currently is. This is expected to cause the real price of natural gas within the state to rise to about $3.40/mcf (in 1975 dollars) by 1985. However, there is a possibility that intrastate sales of natural gas could come under regulation. In order to analyze the effect of such regulation, we simulated a case which has all its assumptions identical to the base case except that the real price of natural gas was held fixed at the 1975 level ($1.41/mcf in 1975 dollars). This case is referred to as the "base case (regulated intrastate gas prices)".

2.4 Alternative Policy Scenarios

Assumptions regarding the alternative supply scenarios used to bracket the base case are discussed below.

2.4.1 Constrained Nuclear Case

This scenario assumes that all nuclear fueled capacity beyond that which has already been planned or committed (9.9 Gw), will be curtailed. However, existing and already planned nuclear plants will be allowed to operate at rated capacities. This situation is similar to those proposed by the nuclear moratorium initiatives that were put to vote in a number of states. Expansion of nuclear power in the state could be curtailed by such a referendum or by a number of other possible occurrences. Federal inaction on the decision regarding the safety of certain nuclear plant designs, the nonclosure of the nuclear fuel cycle, the failure of federal authorities to agree on regulations for spent fuel handling, and the growing public distrust (whether justified or not) on nuclear power, could all combine to curtail the growth of nuclear capacity.

Under this basic assumption of a 9.9 Gw limit to nuclear capacity in Texas, the scenario has been split up into three sub-cases, each providing an alternative way for supplying base load power. The first assumes predominant use of North Texas lignite, the second allows for substantial use of South Texas lignite, and the third assumes that western coal will be used predominantly. The three alternative supply assumptions are differentiable from the environmental and ecological standpoint, but are not assumed to be different from an economic standpoint. The electric utilities that currently use lignite assign a price to it equal to the cost of production. Lignite has not been traded on the market and hence does not have a market price. However, lignite use for generating electricity has been almost insignificant till now and pricing has not been a major issue. But in the future, when lignite use becomes substantial, the price of lignite can be expected to approach a level that would essentially equate the cost of generation by lignite to that of coal. Thus, if capital costs of lignite plants are assumed to be slightly higher than those of coal plants, (because of environmental and material handling equipment differences), the fuel cost per unit heat content of lignite will be slightly smaller than that for coal, the lower fuel cost just about compensating for the higher capital cost. Therefore, from an economic standpoint there will be no difference in the cost of electricity generated by either of the two fuels.

However, environmentally the alternatives are quite different. North Texas lignite has ash and moisture contents that are lower than those of lignite occurring in South Texas. Coal, on the other hand, is relatively cleaner than both the lignite alternatives.

The lignite available in North and Central Texas is primarily under the control of Texas Utilities Company. Smaller lots are owned by individual property owners, and attempts are under way to consolidate the holdings into mineable tracts. It is clear that this process will take time, and property owners can be expected to demand royalties on the land that will essentially raise the price of lignite to levels that will make it equivalent to coal on a btu basis.

Texas Utilities Company, which controls a major share of this lignite, has the option of selling the lignite to other utilities in Texas by means of joint plant ownerships, or it can keep the lignite for its own use. The first subcase assumes that the utilities will build jointly owned lignite-burning plants in North and Central Texas and will transmit this power to their respective service areas. The second subcase assumes that southern utilities will not be able to share the northern lignite and therefore will resort to the use of lignite from South Texas. Both cases assume that the use of lignite will be permitted beyond what has already been committed. The third case is designed to demonstrate what might happen if no new lignite commitments are allowed beyond those already planned and electric utilities have to resort to using western coal.

The scenario that uses South Texas lignite is probably not a feasible one because of environmental considerations. Preliminary calculations show that SO_2 emissions would be extremely high. Another problem expected is in the area of water availability. Both these areas have been investigated and will be reported in the section on environmental analysis. This scenario is included to emphasize the problems that will arise if South Texas lignite use is escalated.

2.4.2 Medium Air Quality

This case has moderately restrictive air quality standards as compared to the base case. No new lignite plants beyond those already committed are allowed to be built. The capital cost of coal plants is assumed to be $30/kw higher than that in the base case (1975 dollars) to represent more effective air pollution abatement equipment.

Coal use, however, is not restricted to low sulfur coal and therefore its price is the same as in the base case. Nuclear power growth is constrained as in the base case to a maximum of 20 Gw.

This case brings out the economic and environmental differences that arise between the base case, which uses substantial quantities of lignite, and a situation in which lignite use is curtailed. It is also assumed that the environmental standards that disallow new lignite commitments would necessitate improved, and therefore more expensive pollution control equipment on coal plants. This is not an unlikely situation, as our analysis shows that increased use of lignite, especially in South Texas, could result in very high air emissions. This coupled with more stringent air quality standards could result in curtailment of lignite-fired capacity to existing levels of commitment. Another reason for lignite capacity curtailment could very well be the absence of cooling water near the lignite sources. Locating lignite plants on the coast would not be practical, as transporting lignite is uneconomical.

2.4.3 High Air Quality

This case has more restrictive air quality standards than the base case. No lignite commitments beyond those already planned will be allowed and new coal plants will have to be built with efficient scrubbers and precipitators. The environmental requirements necessitate the best available technology standards on air emissions and on wastewater.

In addition to installing pollution abatement equipment, generating plants will have to use low sulfur fuel. Western coal with low sulfur content will be used in coal plants and desulfurized oil (0.1%S) in oil-burning plants.

This scenario further assumes that in the interest of maintaining air quality standards, nuclear power growth will not be constrained by fuel availability. Uranium fuel will be available for light water reactor capability beyond the 20 Gw limit imposed in the base case.

The purpose of this case is to emphasize the need for higher rates of uranium exploration which will be essential if high air quality standards are to be met. Installation of pollution abatement equipment and increased fuel costs due to the use of low sulfur fuel will cause the cost of generation by fossil plants to rise. The only options left are the use of nuclear power or the curtailment of electricity demand. Therefore, this scenario, in addition to bringing out the impact of high air quality standards, underscores the need for exploration of nonfossil fuel sources and also forced conservation.

The scenario described here is likely to be realized if utilities in Texas are forced to comply with very stringent air quality standards.

2.4.4 Gas Consumption Zero by 1985

This supply scenario is an exaggerated version of the Texas Railroad Commission Order (Docket #600) restricting the use of natural gas as a boiler fuel. The restrictions on gas usage in this case are extremely severe, leading to zero gas usage by 1985. Most of the other states which relied to a greater or lesser extent on gas-fired capacity have already instituted measures to completely eliminate natural gas use. Some have agreed that electricity generation using natural gas as a boiler fuel is a wasteful use of natural gas. Besides, the price of natural gas is rising to levels that make it uneconomical for electricity generation.

This situation is simulated in the model by stopping all new construction on gas plants and converting some existing gas capacity each year to oil and coal until there is almost no electricity generation by natural gas in 1985 and thereafter. The conversions are done gradually at first and much faster later in order to avoid undercapacities and low reserve margins.

The prices used are the same as in the base case for coal and oil. However, the gas price is reduced to $1.31/mcf (in 1976 dollars) by 1985, because of low demand. Air and water quality standards are the same as in the base case.

2.4.5 Load Management

Currently the aggregate load factor for electric utilities in

Texas is about 45%. This number is relatively low, but as Texas gets more industrialized and load management policies are implemented, it can be expected to increase to somewhere near the corresponding nationally aggregated value.

Federal authorities have recommended legislation for improving usage factors. Various pricing schemes have been suggested. However, as the model used in this study does not compute rate structures, but only an average price of electricity, the effects of pricing schemes have not been dealt with. Rather, for the purpose of this case, it is assumed that the average load factors in Texas will improve to an aggregate value of 68% by 1985 by unspecified means. Whether this is realistic is questionable, but this targeted value has been recommended by federal authorities. All other parameters of this case are assumed to remain at base case values.

The higher load factor is represented in the model by flattening out the load curve. The effects of the improved load curve are expected to be in the area of generating plant capacity requirements, reserve margins, and electricity price. As demand trends are exogenously specified, no demand response is simulated. This case has been simulated and reported to illustrate the impact of improved load factors on electricity supply.

2.4.6 Ground Level Standard

Ground level air quality standards are also referred to as ambient air quality standards and are in use in England and in certain areas in the U.S. Under these standards air emissions in the environment are monitored regularly to determine whether they are within the allowable limits. If the limits are exceeded, coal plants have to burn oil until the emissions reach permissible levels.

This scheme does not require the installation of scrubbers on coal plants, and hence capital requirements are reduced. However, as coal plants will need to burn oil for about 10% of their generation, the fuel costs will be slightly higher.

This case is included to demonstrate what might happen if the government decides not to impose strict environmental standards in favor of supposedly cheaper electricity. The implementation of these standards is not an easy task when wind patterns are not well established. This situation would make implementation of air quality standards extremely difficult, especially when populated areas are downwind of a number of lignite/coal plants. However, in Texas, the major metropolitan areas are generally upwind of present or planned lignite plants.

This case has been implemented in the model by reducing the capital costs of coal and lignite plants so as to exclude scrubbers, and 10% of their generation is assumed to be oil-fired. Other parameters are assumed to be the same as in the base case.

2.4.7 Constrained Supply Case

The cases described earlier have supply restrictions on one or the other fuel type. The last case analyzed and reported is a "worst case" scenario that has restrictions on most of the available fuel resources. Such a situation is not necessarily an unlikely event and perhaps may occur if the proposed and planned constraints on different fuel types are actually realized. The combination of constraints from the previous cases placed on fuel supply and/or use and assumed to exist in this case are as follows.

- Natural gas consumption by electric utilities is forced to zero by 1985.
- Environmental considerations restrict the use of lignite and make coal use uneconomical because of the high cost of reliable equipment for SO_x removal.
- Environmental restrictions curb the use of fuel oil having sulfur content higher than 0.1%. Desulfurization of fuel oil, which will cause oil prices to increase, may be necessary.
- Enforcement of the Energy Supply and Environmental Coordination Act of 1974 forbids the construction of new generating plants that burn oil.

In addition to the constraints imposed on the use of fossil fuel in this case it is also assumed that -nuclear power is constrained to a limit of 20 Gw in Texas due to lack of adequate uranium supply.

The effects of these constraints, both regulatory and economic, on electric supply could be drastic. Reserve margins can be expected to be low and capacity shortages might occur. An analysis of the full impacts of such a shortage is not contained in this report, only the effects on margins of reserve and electricity prices are reported. This case is included to emphasize that the range of constraints being considered on expansion of electricity supply could prohibit reliable electricity service in the future.

CHAPTER 3

RESOURCE OUTLOOK

3.1 INTRODUCTION

This chapter discusses the availability of alternative resources for fueling electric power plants in Texas. In the past natural gas has been the principal fuel used for generating electricity. However, the recent decline in its availability has forced electric utilities in Texas to look for other fuels. Nuclear, coal, lignite, and oil are the principal alternatives that could be used for electricity generation in lieu of natural gas. Each of these alternatives, though currently available, is likely to have either regulatory or supply based restrictions on future use. The following sections discuss the alternative fuel supplies in light of the constraints on their availability. Also discussed are peripheral areas such as transportation, water availability, and plant capital costs.

3.2 COAL AND LIGNITE RESOURCES

In this section we study the coal and lignite resources in the state as alternative energy suppliers to meet the ever-growing market demand.

Tables 3.1 and 3.2 represent a summary of the overall coal and lignite resource picture in the state of Texas.

Bituminous Coal[1]

There are six coal fields in Texas which can be broadly categorized as major and minor. This classification is based on factors such as quantity, quality, distance from the demand center and economics. Figure

[1]This section is a summary of reference [2].

TABLE 3.1

COAL RESOURCES IN TEXAS - 1974
(Millions of short tons)

	Bituminous Coal	Lignite
Resource Estimate	6,100	10,426
Production	26	85
Production Plus Loss in Mining	52	133
Remaining	6,048	10,293

Source: Reference [3]

TABLE 3.2

TOTAL ESTIMATED REMAINING COAL RESOURCES OF TEXAS
(Millions of short tons)

Bituminous Coal	6,048
Subbituminous Coal	-
Lignite	10,293
Anthracite	-
Semianthracite	-
TOTAL	16,341
Estimated hypothetical resources in unmapped unexplored areas	112,100
Estimated total identified and hypothetical remaining in the ground	128,441
Surface minable	3,272

Source: Reference [3].

Bituminous coal and lignite supplies are studied in more detail in the following two sections.

3.1 shows the location of these coal fields.

Major coal fields:

1) North Central Region, west of Fort Worth -

United States Geological Survey (USGS) [reference 3] estimates that there exists close to 5400 million short tons of coal in seam thickness of at least 14 inches. The following table classifies this estimate in terms of overburden thickness.

TABLE 3.3

USGS ESTIMATE OF COAL RESOURCES IN NORTH CENTRAL TEXAS
(Millions of short tons)

Overburden		Amount
0-1000		3,400
1,000-2,000		1,300
2,000-3,000		680
	TOTAL	5,380

The coal in this area has a high percentage of ash and sulfur and thus is of fair coking quality.

2) Santo Tomas District, Webb County -

Inferred original resources for this area are estimated by Mapel [reference 4] and are as follows:

Santo Tomas Seam	24 Inches Thick	90 Million Tons
San Pedro Seam	10-18 Inches Thick	24 Million Tons
	TOTAL	114 Million Tons

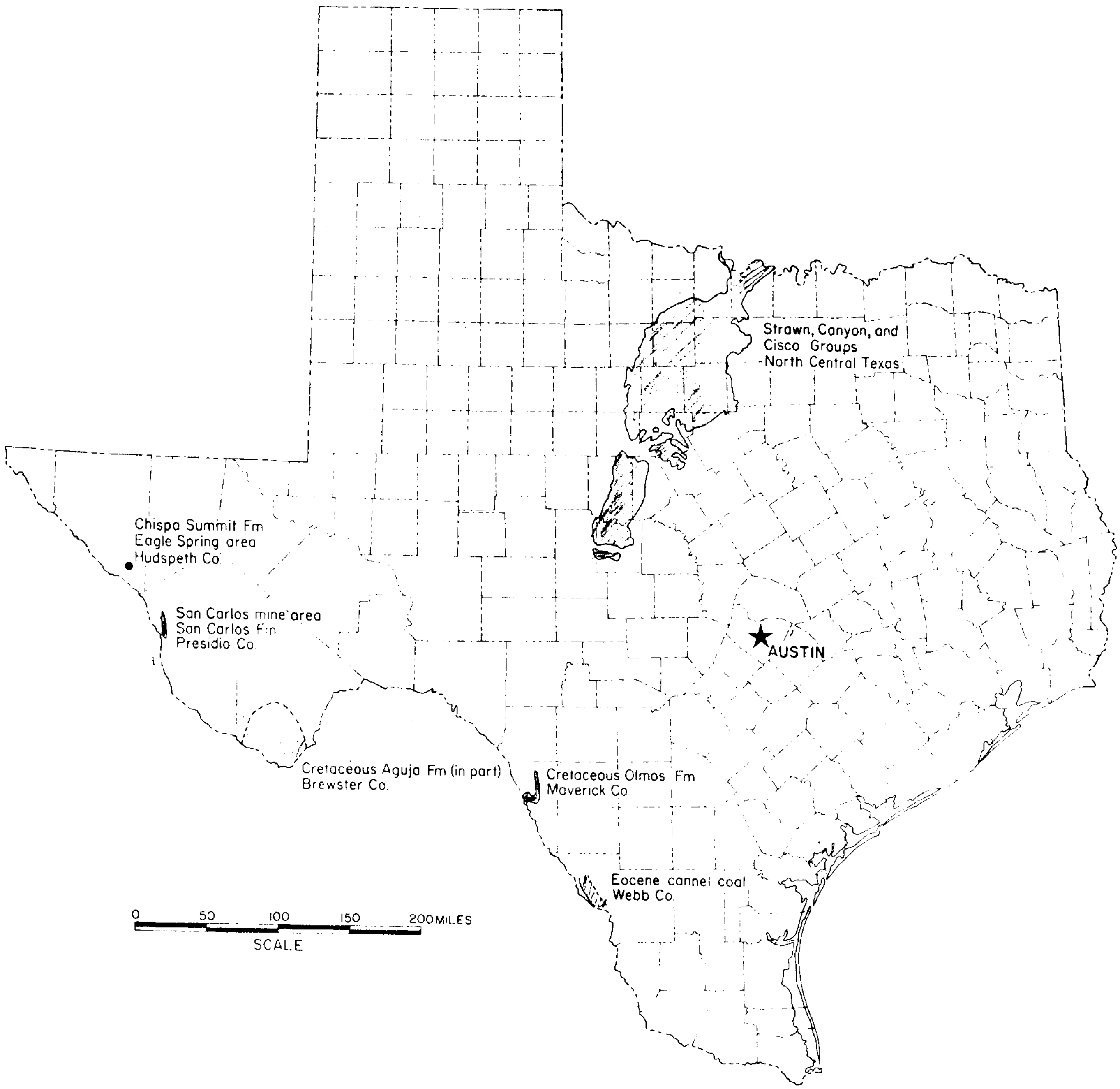

FIGURE 3.1 LOCATION OF TEXAS BITUMINOUS COALFIELDS AND GENERALIZED OUTCROP OF COAL-BEARING STRATA

Source: Reference [2].

3) Eagle Pass Area, Maverick County -

Mapel, [Reference 4] reports the most recent estimate of coal resources in this area at 525 million short tons in the following two categories:

Seam Thickness	Amount
6.0 ft	125 Million Tons
2.0 ft	400 Million Tons

Minor Coal Fields:

4) San Carlos Region, Presido County -

It is estimated (Mapel, reference 4) that 25 million short tons of coal are present in this area in beds thicker than 14 inches at depths of 3,000 feet or less.

5) Big Bend Region, Brewster County -

Although a more detailed and reasonable estimate of coal resources in this area is needed, as much as 65 million tons may be present. Seams of up to 3 feet are reported. Analysis of samples has shown that the coal is of poor quality with high moisture, ash, and sulfur content.

6) Eagle Spring Area, Hudspeth County -

No estimates of coal resources and reserves are available at this time. Information on quality of this coal is also scarce.

In summary, the bituminous coal resource and reserves in Texas are estimated to be 6.1 billion tons in beds at least 14 inches thick and as much as 3000 feet below the surface. Texas coal production reached its maximum in 1917 at 1.25 million tons but suffered a sharp decline in the early

Table 3.4 summarizes the properties of bituminous coal existing in different regions.

TABLE 3.4 [2]

SUMMARY OF PROXIMATE[3] ANALYSIS: TEXAS BITUMINOUS COAL
(All numbers are in weight - percent except the heat content)

Parameters \ Coal Seams	North-Central Texas				Santo Tomas district	Eagle Pass	Big Bend	San Carlos
	Strawn Group (mainly Thurber)	Canyon Group (Bridgeport)	Cisco Group (Newcastle)	Cisco Group (others)	Claiborne Group cannel coal	Olmos Formation	Aguja Formation	San Carlos Formation
Moisture	3.6	11.9	11.8	6.4	3.7	6.4	6.1	2.3
Volatile Matter	33.9	32.6	35.3	36.5	45.6	33.2	30.4	37.8
Fixed Carbon	47.1	42.2	38.7	43.0	36.4	42.0	48.4	38.0
Ash	15.2	13.5	14.3	13.8	14.2	18.4	15.1	21.8
Sulfur	2.4	2.1	3.3	3.7	2.2	1.4	1.4	0.8
Heat Content Btu/lb.	11,641	10,038	9,565	9,980	11,640	10,682	10,064	10,056

[2]Source: Reference [2].

[3]Proximate analysis deals with physical and chemical properties of concern when the material under study is used in combustion.

1920s. Production stopped in 1943 because of the availability of cheap natural gas and oil.

LIGNITE[4]

During the period 1850 to 1930, lignite was a major energy source, but its production declined and finally stopped as more economical oil and natural gas became available. The production peaked at 1.2 million short tons in 1918 but declined to a minimum value of 18,000 tons in 1950. Once again, however, lignite production is on the rise. This upward trend is shown in Table 3.5 in which the major operating or planned lignite-burning power plants are listed. Present production is 8 to 10 million short tons.

TABLE 3.5

OPERATING AND PLANNED LIGNITE PLANTS

Plant Name	Capacity	Location	Year Operation Starts
Sandow	360	Milam County	1954
Big Brown	1150	Firestone County	1971
Monticello	1150	Titus County	1975
Martin Lake	1500	Rusk County	1977
San Miguel	800	Atascosa County	1978
Forest Grove	750	Henderson County	1981
Twin Oak	1125	Robertson County	1982

These plants, when operational, will consume 20 to 30 million tons of lignite per year.

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[4]This section is a summary and overview of reference [1].

Texas's supply of lignite resources can be categorized according to depth as follows:

TABLE 3.6

DEPTH OF TEXAS'S ESTIMATED LIGNITE SUPPLY

Depth (Feet)	Amount (Billion short tons)
90	3.3
200	10.4
200-5000	> 100

Not all of this resource is economically minable at present, but its volume is sufficient to have a large impact on the state's future energy picture.

Texas lignite, mostly in Wilcox group and widely distributed in Texas Gulf Coastal Plains, exists as near-surface and also as deep-basin deposits. Figures 3.2 and 3.3 show the geographical locations of the resource.

Near Surface Deposits:

Lignite with overburden of 0-200 feet is considered near surface since it can be recovered with present strip-mining technology. This deposit is mostly in Wilcox Group and in the less important Yegua Formation and Jackson Group. Three areas should be considered for the Wilcox lignite.

1) East Texas -

This area has a past history for deep mining but at the present time only strip mining is being used to provide lignite for the manufacture of activated carbon and power plant fuel. A large portion of the deposit in this region is of the fluvial type. Potential reserves are estimated at 5,085 million tons.

2) Central Texas -

The area along the Missouri-Kansas-Texas railroad is the most exploited for lignite in Texas. Presently there are two large strip-mining operations in this area. An estimate of the potential resource is 2,846 million tons, it is mostly deltaic lignite.

3) South Texas -

It is estimated that 676 million tons of lagoonal lignite, in thick beds but of discontinuous formation, exist in this area. This deposit cannot be used for direct combustion because of its high sulfur content.

Near-surface lignite in Yegua formation and Jackson Group are found in two areas:

1) Southeast Texas -

There has been some mining in this area in the period 1900 to 1930. This deposit, because of its poor quality, has potential only for future utilization. There are an estimated 1,386 million tons of lignite in this deposit, which is mostly deltaic.

2) South Texas -

Potential reserves are estimated at 434 million tons of poor quality lagoonal lignite. Table 3.7 summarizes the regional compositional variation of Texas lignite.

TABLE 3.7 [5]

AVERAGE REGIONAL COMPOSITIONAL VARIATION OF TEXAS LIGNITE
(All numbers are in weight - percent except the heat content)

	As Received					Dry Basis				
	Volatile matter	Fixed carbon	Ash	Sulfur	Btu/lb	Volatile matter	Fixed carbon	Ash	Sulfur	Heat Content Btu/lb
Wilcox East	35.70	26.76	9.95	0.81	7,705	47.44	38.50	13.78	1.01	10,482
Wilcox Central	33.82	29.49	9.10	1.00	7,916	47.65	39.64	12.17	1.41	11,033
Wilcox South	33.51	27.55	15.10	1.66	7,508	49.28	33.03	16.47	1.68	10,979
Yegua-Jackson Southeast	34.89	21.79	10.96	0.83	7,124	= 51.15	32.17	16.72	1.47	10,594
Yegua-Jackson South	28.83	21.01	40.84	1.78	6,130	32.35	23.08	40.82	1.93	6,826

Statewide Moisture 26.76

[5] Source: Reference [1].

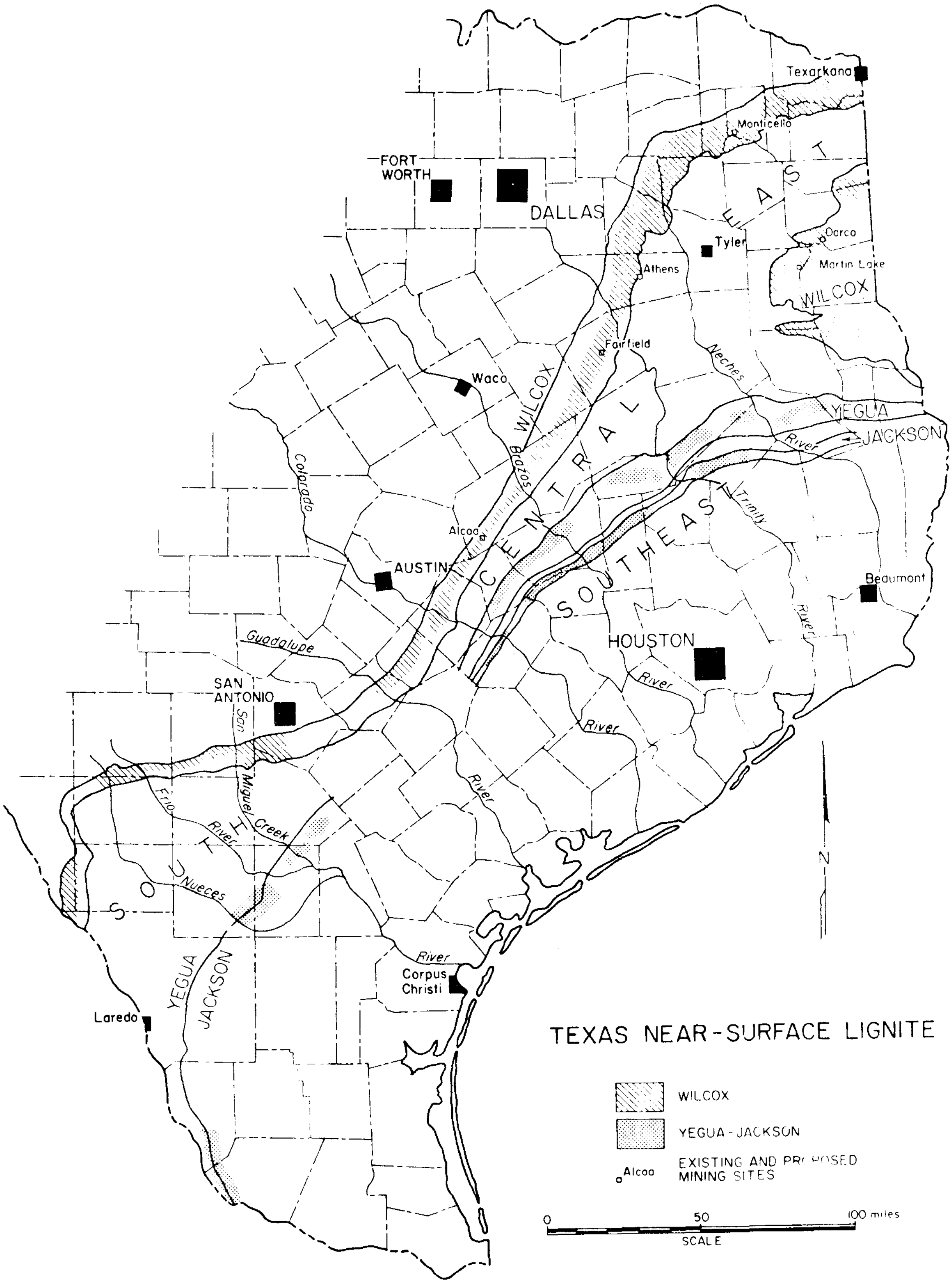


FIGURE 3.2: DISTRIBUTION OF TEXAS NEAR-SURFACE LIGNITE

Source: Reference [1].

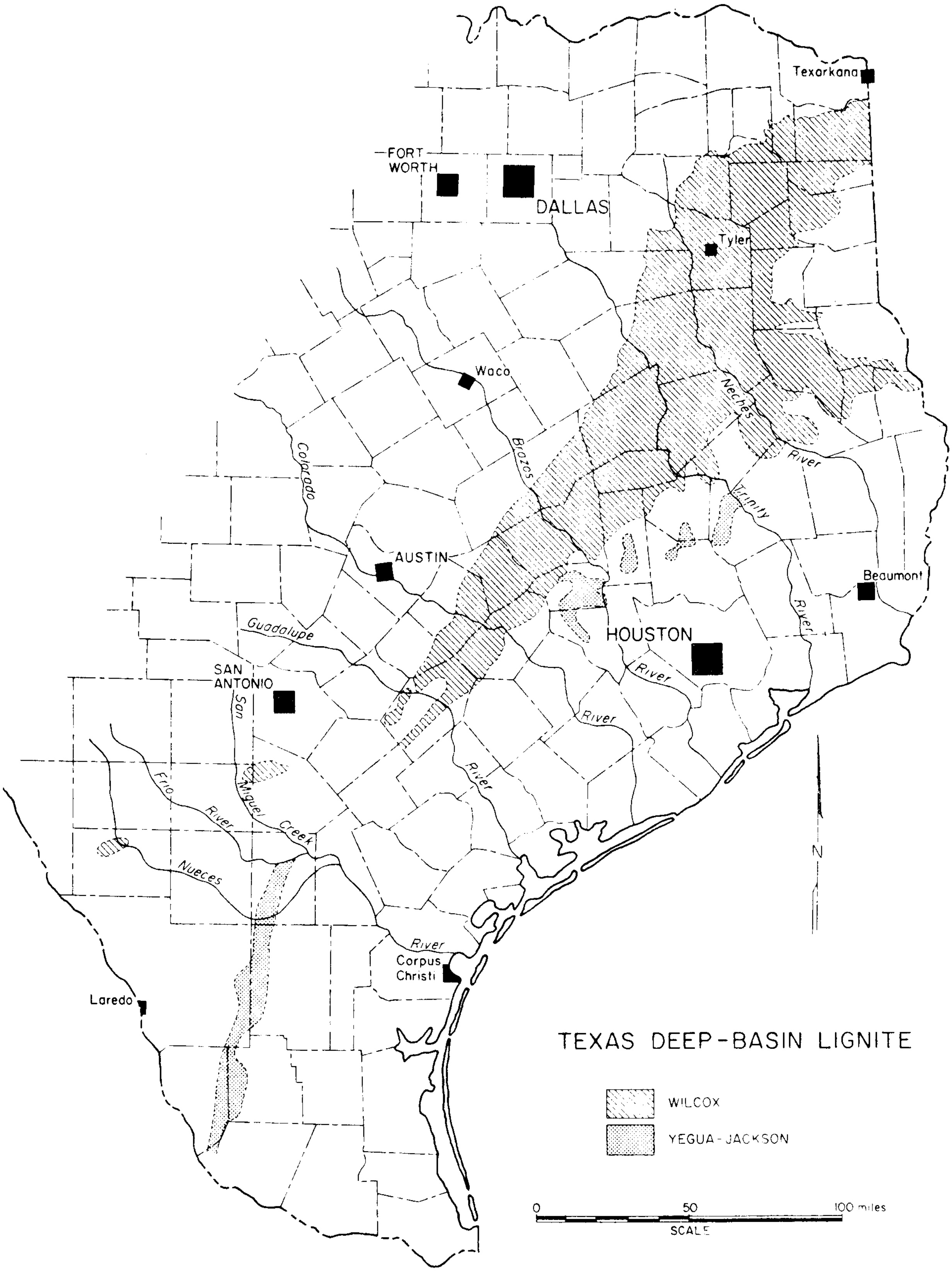


FIGURE 3.3: DISTRIBUTION OF TEXAS DEEP-BASIN LIGNITE

Source: Reference [1].

DEEP DEPOSITS

Deposits with overburden of more than 200 feet are called deep deposits. Because of the availability of near-surface lignite, the deep-basin resources are considered only for future utilization in processes like in situ gasification. It is estimated that more than 100 billion tons of lignite exists in Texas in depths ranging from 200 to 5000 feet.

In conclusion, lignite is considered as a major energy resource alternative, and production is expected to exceed 25 million tons in 1980. Its most important future utilization is in electricity generation, but production of liquid fuels, synthetic gas, and chemical feedstock will increase the demand for this plentiful resource.

MINING OPERATIONS FOR LIGNITE

1. Surface

Surface mining in Texas can cause severe ecological problems if proper reclamation precautions are not taken. The lands in southwest Texas are prairie types which are dusty and have little or no topsoil to be replenished. These soils are contrasted with East Texas soils, which in many cases, are already under extensive agricultural or forestry development programs.

The Texas Utilities Company has served as a leader for land reclamation (management) in lignite surface mining. They reported a 5-year cycle of crops-lignite-crops for the mining operations in Fairfield, Texas. The exact cost of land reclamation was not known but was reported as $50-500/acre. The success in land reclamation was due to the novel method of mining and recovery which was carried out simultaneously.

They remove topsoil first and deposit it for storage; next the covering over the lignite is removed and placed on higher ground where there is no topsoil. The lignite is next removed and, while the lignite is being removed, the soil is being leveled and overlaid with topsoil. The next soil removed is placed where the first pit was uncovered. Various grasses and crops have been planted on the reclaimed land. Of the successful crops reported--sorghum, corn, sotton, and soybeans--sorghum was the most promising.

Prairie soils may be hard to revegetate owing to small amounts of rainfall. Most minable lignite deposits are within 340 feet of the surface, with one-half mile being the minimal length of the pit for economic recovery. The deposits of lignite are found in veins from 4 to 7 feet thick. Radon gas releases have been reported in some areas although no data are known regarding the exact amount of these releases.

2. In Situ Recovery

This method of recovery is not well suited for power generation where the lignite deposits are close to the surface, because of the low yields. Deeper deposits make in situ recovery desirable because of the high costs involved in the mining of deep deposits by conventional methods. The lack of interstitial bonding in Texas lignite (as evidenced by its powdery characteristics) makes the carbon more reactive (as less energy has to be exerted to break the lattice structure). This means that less steam per cubic foot of gas has to be used, resulting in greater thermal efficiencies experienced with in situ gasification of Texas lignite. Thermal efficiencies of up to 80% have been reported, although yields range from 50-60%. The U.S.S.R.

has experimented with a 4-Mw power plant and has a 250-Mw power plant in the planning stage.

Dr. T.F. Edgar of the University of Texas Chemical Engineering Department has shown that wide thick seams have the best yield. The overall reaction is--$C + H_2O \rightarrow CO + H_2$--a good method for feedstock production or producer gas.

WATER

Lignite deposits are not as permeable as the ground above them and thus serve as the bottom for many natural aquifers. When this is the case, care must be taken to insure against contamination of water supplies and/or excessive draw-down of nearby wells. If a major lateral portion of an aquifer is disturbed, placing of coarse gravel and sand for an artifical aquifer may be necessary. Some of the East Texas lignite unfortunately lies in a flood plain. When this is so, flood prevention and water pumping may be necessary.

The semiarid conditions of South Texas will require about 1 acre-ft of water per 18,250 tons of lignite mined and 2 acre-ft of water per acre of land mined and reclaimed for revegetation. For a mining operation of 25,000 tons/day, total water requirements can exceed 4,000 acre/feet/year (irrigation and rainfall). The plant requirements are estimated at 1,000-1,300 acre-ft/Mw if once-through cooling is used and as much as 200-2600 acre-ft/Mw if cooling ponds or towers are used. Water intake requirements to replace water lost through blowdown and evaporation will be on the order of 2000-5000 acre-ft/Mw. The once-through systems appear to be an unlikely alternative due to the high intakes.

A projected lignite capacity of 10,350 Mw will be about 15% of state generating capacity. Lignite mining to supply this capacity could exceed 50 million ton/year. If growth continued at this rate, more than 130 million tons could be under development by the twenty-first century. If it is assumed that most lignite goes for steam power generation, the water demand could exceed 300,000 acre-ft/year, straining available water supplies in Texas. Water needed for cities, industry, and agriculture is already spoken for by water rights permits, meaning difficulty in procuring water.

COMBUSTION PROCESSES

Because of the expected fouling tendencies of lignite, boilers are designed with considerable furnace height (205 feet as compared to 130-150 for standard) and low volume heat release rates. Other features for controlling ash fouling include wide tube spacing and shallow tube bank depths in the convection section, steeply sloped floors under pendant surfaces for shedding deposits into the main furnace, and a large number of soot blowers.

Three major methods of burning lignite are in practice today. Fluidized bed reactors are being studied because lower emission rates of particulate matter, SO_2 and NO_x are obtained as a result of the lower reaction temperature.

a. Spreader-Stoker Method of Firing

Large size coal chips are placed on a grate and air is blown over the chunks. The chunks move through the furnace bed at a rate that is equal to the burning rate of the median size coal chunk so that the retention time is equal to the firing time.

Although the inefficiencies in firing of the fuel generally eliminate the spreader-stoker method from power generation, the lower capital cost and operating cost (due to less pulverizing equipment) make it desirable for small industrial and power operations. A 66-Mw lignite-fired unit supplies electricity to Mandan, North Dakota.

b. Pulverized Coal

The pulverized coal method has become the standard firing method for coals because the furnace can be loaded easily. The coal is ground to a much finer mesh than for the stoker or cyclone furnaces and is fed via an air-lignite slurry directly into the furance, where it is ignited. Because of the fouling tendencies of lignite, low volume heat release rates are used of around 7,200 Btu/feet^3 hour.

Utility engineers in Texas will pay careful attention to the performance of the 400 Mw San Miguel plant because it is using some of the worst coal ever used for power generation.

c. Cyclone Furnaces

Cyclone furnaces have become increasingly popular; in 1970 about 700 cyclone furnaces were serving 150 boilers in the U.S. The reason for this influx is that lower grades and ranks of coals and lignite are readily amenable to cyclone firing. The higher flame temperatures encountered in cyclone firing cause the ash to fuse to the walls of the furnace, thus preventing the heat transfer surfaces from fouling as quickly. This factor results in an ash emission that is 25-38% that of the pulverized coal method.

The furnace size is smaller than for pulverized firing at 12,000 Btu/ft^3 hour (Table 3.8). Because of the high percentage of moisture, the lignite from the feeder is mixed with 750°F primary air and carried through the hammer mill crusher where 10-12% of the total moisture is removed. This "cool" mix of moist air is vented into the furnace above the top row of cyclones. The dried lignite is picked up by a rotary seal feeder and fed into another stream of 750°F air and from there to the cyclone.

EMISSIONS FOR DIFFERENT COMBUSTION PROCESSES

Table 3.9 shows the emissions for different lignites fired with spreader stoker, pulverized coal, and cyclone furnaces.

The cyclone furnace has the lowest ash emission but the highest nitrogen exides emission. This high nitrogen oxide emission of the cyclone furnace is due to the high flame temperature.

PARTICULATE MATTER

Recent experience with electrostatic precipitators on power plants burning North Dakota lignites has been good. All operating units have met or exceeded design efficiencies. These units were designed with specific collecting areas from 235-375 ft^2/thousand actual feet for removals in the range of 97-99.5%. The design is only slightly more conservative than for the earlier units operated on subbituminous coals, considering similar removal efficiencies. The superior performance of units operating on lignite is at least partly due to differences in the properties of coals, with the

TABLE 3.8

FURNACE CHARACTERISTICS

Furnace	Fuel	Height (ft)	Heat Release Rate Btu/ft^3-hr
Spreader-Stoker	Lignite	N.D.	N.D.
	Coal	75	7,500
Pulverized Coal	Lignite	205	7,300
	Coal	115-130	N.D.
Cyclone	Lignite	204	12,100
	Coal	150-180	24,000

TABLE 3.9

TYPICAL EMISSIONS OF LIGNITES IN VARIOUS FIRING METHODS

Furnace	NO_x lbs/ million Btu	SO_2* lbs/ million Btu	Ash lbs/ million Btu	Lignite
Spreader-Stoker	.29	1.8	N.D.	1% S-North Dakota (6000 Btu/lb)
	.29	1.2	N.D.	0.9%-Wilcox (7590 Btu/lb)
	.29	2.9	N.D.	1.5% San Miguel (5000 Btu/lb)
Pulverized Coal	.38-.66	1.8	8	North Dakota
	.38-.66	1.2	11	Wilcox
	.38-.66	2.9	42.6	San Miguel
Cyclone	.73-.86	1.8	2	North Dakota
	.73-.86	1.2	2.75	Wilcox
	.73-.86	2.9	10.7	San Miguel

*doesn't account for SO_2 held in coal ash.

lignites having a higher moisture content and more sodium in the ash. The operating problems of electrostatic precipitators on boilers burning lignite are concerned mainly with removal of fly ash from the hopper; and on spreader stoker units, combustion of carry-over in the electrostatic precipitators hopper can cause ash clinkers.

Wet scrubbers for particulate control have been installed on 10 boilers burning low-rank U.S. coals. The designs represented are of three types: 1) venturi scrubbers, 2) high pressure impingement scrubbers, and 3) turbulent contact absorbers (TCA) in which flue gas is passed counter-current to scrubber liquid through a bed of light plastic balls.

All of the scrubbers operating on low rank coals have successfully met applicable emission standards, and in addition, have removed some portion of the SO_2 entering the flue gas. The precipitation of gypsum ($CaSO_4$ $2H_2O$) seriously reduces the reliability and availability of a scrubber. This scaling problem has forced most scrubber operations to continuously dilute recirculating liquor to remain below saturation with respect to $CaSO_4$ and to remove a corresponding amount of blowdown which must be disposed by discharge to streams or by evaporation in ponds. Current designs include both an electrostatic precipitator for particulate matter and a scrubber for SO_2 removal.

SO_2

The sulfur content of most lignites is reasonably low, about 1% on a dry basis. This percentage corresponds to 840 ppm_v or 1.8 lb SO_2/million Btu emissions requiring 30-40% removal to meet Environmental Protection Agency standards of 1.2 SO_2/million Btu. Eighty percent of the U.S. flue gas desulfurization (FGD) systems are lime and limestone, with magnesium oxide, Sodium carbonate, and Wellman-Lord comprise 9.25% and 6.8%, and the rest are uncommitted. The 1980 market appears to be 55-70%, 8.8%, and 35% respectively.

An important property of lignite is that it contains more alkali in the form of calcium, magnesium, and sodium than sulfur. This alkali can be used as an agent to remove SO_2 in a wet scrubber. The range of stoichiometric ratios of alkali to sulfur vary from 0.5-5 (the higher the better for ash alkali removal). The higher this ratio, the larger percentage of SO_2 removed.

Pilot plant studies on scrubbing with ash alkali have demonstrated SO_2 removal efficiencies in the range of 40-95%, with lime and limestone-ash systems in a range of 40-70%. The waste produced is a sulfate enriched fly ash sludge containing varying amounts of soluble salts, primarily sodium and magnesium sulfates, and has good setting properties. In Texas there are proposed lignite flue gas desulfurization systems for six generators at three locations: Martin Lakes # 1, 2, 3, 4, 750 Mw each; Monticello #3, 750 Mw; San Miguel #1, 400 Mw, with limestone-based wet scrubbing. By 1981 all six generators will be in operation with an annual estimated limestone requirement of a million tons/year. This represents 2 to 3% of the estimated annual production from the limestone deposits in the vicinity of major lignite-fueled power plants.

The cost of scrubbing adds substantially to the capital cost of a new power plant and to operating costs. The installation cost, including contingencies, for an ash-alkali scrubber presently being built for a 450-Mw plant is about \$30 million (\$66.7/kw). Adjusted costs for lime and limestone base systems reported by 19 utilities ranged from \$50-88/kw with an average of \$70/kw (σ = \$9.48/kw), with other systems being more expensive. Operating costs for both lime and limestone, including capital charges, will be close to \$0.125/million Btu input, about two-thirds of the fuel cost.

NO_x

The current Environmental Protection Agency standard of 0.7 lb NO_x/million Btu was applied only to coals of subbituminous rank and higher, because no data were available at the time of issuance to establish the "best available control technology" for lignite. The Environmental Protection Agency has since issued a draft regulation for lignite, requiring an emission below 0.6 lb NO_x/million Btu. The EPA justifies the lower emission standard for lignite based on an alleged lower fuel nitrogen content and a lower flame temperature for lignite, compared to other coals. The adaptation of this NO_x standard would have the effect of eliminating cyclone firing of 0.73 to 0.89 lb NO_x/million Btu.

NO_x is produced by reaction of O_2 with N in the combustion air and with fuel nitrogen. Fuel-derived NO_x is controlled by the level of coal nitrogen and the amount of oxygen available during volatilization; the contribution of fuel nitrogen to the total NO_x has not been definitely established. The emission derived from combustion air, termed "thermal NO_x" is directly determined by the peak temperature occurring during combustion.

Methods for reducing NO_x during combustion are concerned with controlling the distribution of fuel, oxygen, and temperatures in the furnace. The methods applicable to lignite are low excess air, two stages of stoichiometric combustion, and tangential firing.

Utilities using lignites are concerned that the proposed NO_x standards may have adverse effects on boiler reliability, and particularly on ash fouling. Cyclone firing is believed by some to reduce the rate of fouling because of the smaller amount of fly ash reaching the convection sections of the boiler. This finding has not been substantiated in controlled tests, but such tests may be currently under way. It is also believed that reducing excess air may aggravate ash fouling for pulverized coal firing because of reduced cooling of fly ash by excess air, which could result in requirements for larger boilers and still lower heat release rates. Industry consensus is in favor of a delay in the standard to permit further study of the problem.

CONCLUSION

Because of the high transportation cost (Table 3.10) of coals and lignites and the diminishing supply of petroleum reserves (4% of total energy reserves) for utilities power generation, alternatives which promulgate independence from our petroleum reserves must be developed. The alternatives developed should be based on economic <u>and</u> environmental considerations.

Current energy development trends are already showing increased lignite development (Table 3.11). The 1985 planned lignite capacity is 12,801 Mw, or 15% of the generation capacity, or 3.10 times the 1976 lignite capacity; the total 1985 power increase is 1.5 times the 1976 capacity.

Due to the high content of metals in lignite (Table 3.12 and 3.13), special

TABLE 3.10

TRANSPORTATION COST FOR COAL AND LIGNITE

Mode of Transportation	Cost (cents/ton-mile)
Truck	5-8
Belt	5-6
Train	0.8-1.5
Slurry Pipe Line	0.3-0.7

fouling problems have caused lower heat release furnace designs to be used. Should ash-alkali flue gas desulfurization systems be used, the higher alkali-to-sulfur ratio will be an advantage.

Land reclamation approached on an objective and informed basis will be able to minimize the potential adverse effects of surface mining found in operations without land management.

The question of water resources for lignite development is not resolved. Neither the quantity of water required for lignite development nor the amount of water available is well defined. The obvious fact is that competition for city water will occur without proper management of available water resources.

The emissions of air pollutants from lignites are shown in Table 3.9. They show that the East Texas lignite burned in a cyclone furnace would result in the lowest emission of particulate matter; however, the nitrogen oxides emissions will be higher than the allowable amount of 0.7 lb/million Btu and considerably higher than the draft regulation of 0.6 lb NO_x/million Btu. This necessitates the deferment of cyclone-fired boilers unless sufficient control technology for NO_x is developed. The best alternative is the use of the pulverized coal boiler for the burning of lignite unless nitrogen oxides control technology is made feasible.

The overall emissions due to lignite firing are 2 to 3 times those of coal firing; however, the use of SO_2 scrubbers and electrostatic precipitators can reduce the emissions of all but NO_2 to a tolerable level. A consolidated effort to use regenerative SO_2 scrubbers is called for because of the inherent sludge disposal problems incurred with nonregenerative systems.

TABLE 3.11

LIGNITE USAGE IN TEXAS

A. Current Lignite-Fired Power Generating Stations in Texas

Utility Company	Station or Location	Capacity (Mw)
ALCOA & Texas Power & Light	Sandow S.E. S.	345
Dallas P & L, TESCO Texas P & L Company	Big Brown	1150
DP & L, TESCO, Texas P & L	Monticello	1150

B. Planned Lignite Facilities for Texas

Utility Company	Station or Location	Capacity (Mw)	On-Line Date
DP & l, TP & L, TESCO	Martin Lake #1	750	3-77
	Martin Lake #2	750	2-78
	Martin Lake #3	750	2-79
	Martin Lake #4	750	2-81
TP & L, TESCO	Monticello #3	750	3-78
ST & M, TMPD	San Miguel #1	400	12-79
	San Miguel #2	400	12-80
DP & L, TP & L, TESCO	Forest Grove #1	750	1-81
TP & L	Twin Oak #1	563	1-82
	Twin Oak #2	563	1-83
TMPP	TPPI #1	400	1-82
	TPPI #2	400	1-83
	TPPI #3	400	1-84

Table 3.11

Planned Lignite Facilities for Texas (Continued)

Utility Company	Station or Location	Capacity	On-Line Date
TP & L, DP & L, TESCO	Unassigned TU	400	1-85
	Unassigned TU	750	1-85

Total Planned Lignite Capacity is 8,776 Mw by 1985

Total Planned Capacity by 1985 59,411 - % Lignite = 15%

Present Lignite Capacity 1530 Mw out of 35,000 % Lignite = 4.4%

Amount over 1976 Capacity = 8776/1530 = 5.74

Amount total power is projected to increase = 59,411/35,000 = 1.7

TABLE 3.12

Ash Analysis for San Miguel Plant Lignite

Component	Composition (% by weight)
SiO_2	61.1-65.1
Al_2O_3	16.0-19.5
Fe_2O_3	2.0-3.9
TiO_2	0.7-0.9
P_2O_2	0.04-0.12
CaO	4.0-5.5
MgO	0.5-0.8
Na_2O	2.8-3.7 (0.1% for normal lignite)
K_2O	1.8-2.1
SO_3	3.3-5.9

TABLE 3.13

Ultimate Analysis of San Miguel Lignite

Component	Composition (% by weight)
H_2O	27-35
Ash	24-29
Volatile Matter	21.4-26.2
Fixed Carbon	18.3-18.6
N (dry basis)	0.64-0.84
S (dry basis)	2.2-2.7
Ash (dry basis)	34.9-41.6 (53.3 lb ash/10^6 B)
Heat Value	4200-6350 B/lb

REFERENCES FOR SECTION 3.2

1. W.R. Kaiser, 1974, Texas Lignite: Near-Surface and Deep Basin Resources: The University of Texas at Austin, Bureau of Economic Geology, Report of Investigation - No. 79.

2. T.J. Evans, 1974, Bituminous Coal in Texas, The University of Texas at Austin, Bureau of Economic Geology, Handbook 4.

3. Paul Averitt, 1974, Coal Resources of the United States, January 1, 1974, Geological Survey Bulletin 1412.

4. Mapel, W.J., 1967, Bituminous Coal Resources of Texas; U.S. Geological Survey Bulletin 1242-D.

3.3 Uranium and the Nuclear Fuel Cycle

The process of fissioning heavy atoms such as uranium and plutonium to release energy to generate electricity will be available to utilities in Texas to produce increasing amounts of electricity in the future. Today there exist in the world many varieties of plants based upon nuclear fission including the Canadian Heavy Water Reactor (CANDU); the British and French gas-cooled, graphite-moderated reactors; the British Steam-Generating Heavy Water Reactor (SGHWR); and the High Temperature Gas Reactor (HTGR). But the nuclear system used almost totally in the U.S. is the Light Water Reactor (LWR).

In 1976, 10% of the nation's electricity will be generated by 62 nuclear plants, with 61 of those plants being LWRs. The LWRs within the U.S. consist of two types of commercial designs: the Boiling Water Reactor (BWR) representing about 30% and the Pressurized Water Reactor (PWR) representing about 70% of the plants.

The purpose of this section 3.3 is to discuss the level of demand, the uranium resource base available to meet that demand, and the nuclear fuel costs associated with the demand and resource base. Because of the similarities between the BWR fuel cycle and the PWR fuel cycle, and since PWRs make up a large majority of the nuclear plants in the U.S., demand, resource base, and nuclear fuel costs will be discussed in relationship to a PWR. Further, the Westinghouse Electric Corporation designed PWR is the predominate type of LWR and will be used as the base plant. (See table 3.14)

Table 3.14
REFERENCE NUCLEAR PLANT

	RESAR-41* Westinghouse	RESAR 3* Westinghouse	Reference Plant
Core Power (Mw(t))	3800	3411	3125
Net Elec. Output (Mw(e))	1250	1125	1000
Efficiency	.329	.330	.320
Uranium in Core (kg)	101,427	89,058	80,000

Additional constants used in discussing nuclear fuel are as follows:

a) Uranium metal (kg) to U_3O_8 (lb)

2.5998

b) Feed and separative work units to produce one kilogram of 3 percent enriched uranium.[1]

Tails Assay	Feed Component	Separative Work (SWU)
.200%	5.479	4.306
.250	5.965	3.813
.275	6.250	3.609
.300	6.569	3.425

c) Plutonium feed replacement value

gm U-235/gm Pu Fissile [2] .8

d) Average Region Burn-up Mwd/MTU-Megawatt Days per Metric Ton Uranium [3, 4]:

1st Region	12,000 Mwd/MTU
2nd Region	24,000
All subsequent regions	31,000

e) Initial Core Enrichment (Average) 2.6% [5]

SWU - 220,000 @ .3% 275,000 @ .2% [1]

Note to table on next page.

Notes to table 3.14

1. Dr. Clarence E. Larson, Hearings Before the Joint Committee on Atomic Energy, Congress of the United States, on the Future Structure of the Uranium Enrichment Industry, July 31, 1973.

2. "Plutonium Fuel Management Options in Large Pressurized Water Reactors," Combustion Engineering, December 1973.

3. Discussions with Westinghouse Electric Corporation nuclear fuel personnel, August, 1976.

4. R.R. Henderson, "The Design of PWR Fuel to Meet Utility Requirements and Its Operational Demonstration," Westinghouse Electric Corporation, Nuclex 75, Brussels, Belgium.

5. Reference Safety Analysis Report, (RESAR-41), Westinghouse Electric Corporation, 1973.

3.3.1 Demand

The economics of the nuclear fuel cycle for utilities in Texas will be determined by the overall national nuclear situation, owing to the fact that nuclear fuel is compact and highly transportable. In fact, if multinational nuclear fuel facilities became commonplace, a controlling worldwide market could exist; however, this analysis will assume that onlv a national market situation exists.

To accurately discuss the components of the fuel cycle, an analysis of the level of national commitment to nuclear plants is in order. The following scenario will provide guidelines as to maximum levels of demand on uranium resource base, enrichment capacity, reprocessing/ disposal, and the timing of those demands.

Because of the minimum 30-month licensing period, 60-month lead time for ordering reactor vessels, minimum 60-month construction and testing period, and so forth, the maximum level of nuclear plant additions between now and the end of 1985 is fixed. From the January 1, 1976, level of about 40,000 Mw(e), nuclear plant capacity should have a maximum expansion of 139,000 Mw(e) by the end of 1985 as listed in table 3.15 and figure 3.4. There is little likelihood that the additional 28,000 Mw(e) on order for operation in 1986 and beyond could be brought on line earlier since nuclear equipment manufacturing slots are already tightly scheduled, large quantities of material such as steel might not be available in time, and construction forces would be disrupted if second units were constructed simultaneously with first units at a site.

Beyond 1985, LWR nuclear plant capacity could reach 310,000 Mw(e) as shown in figure 3.5, with this limit more fully explained in the

Table 3.15

NUCLEAR PLANT ADDITIONS

Year	Plants	Mw(e)
1976	8	7,643
1977	6	5,625
1978	10	10,217
1979	8	8,314
1980	12	12,864
1981	17	17,966
1982	18	20,341
1983	20	22,760
1984	18	19,414
1985	13	14,510
	130	139,654

Data is primarily from Survey of United States Uranium Marketing Activity, ERDA, April 1976

Figure 3.4
MAXIMUM LWR NUCLEAR PLANT CAPACITY
(United States)

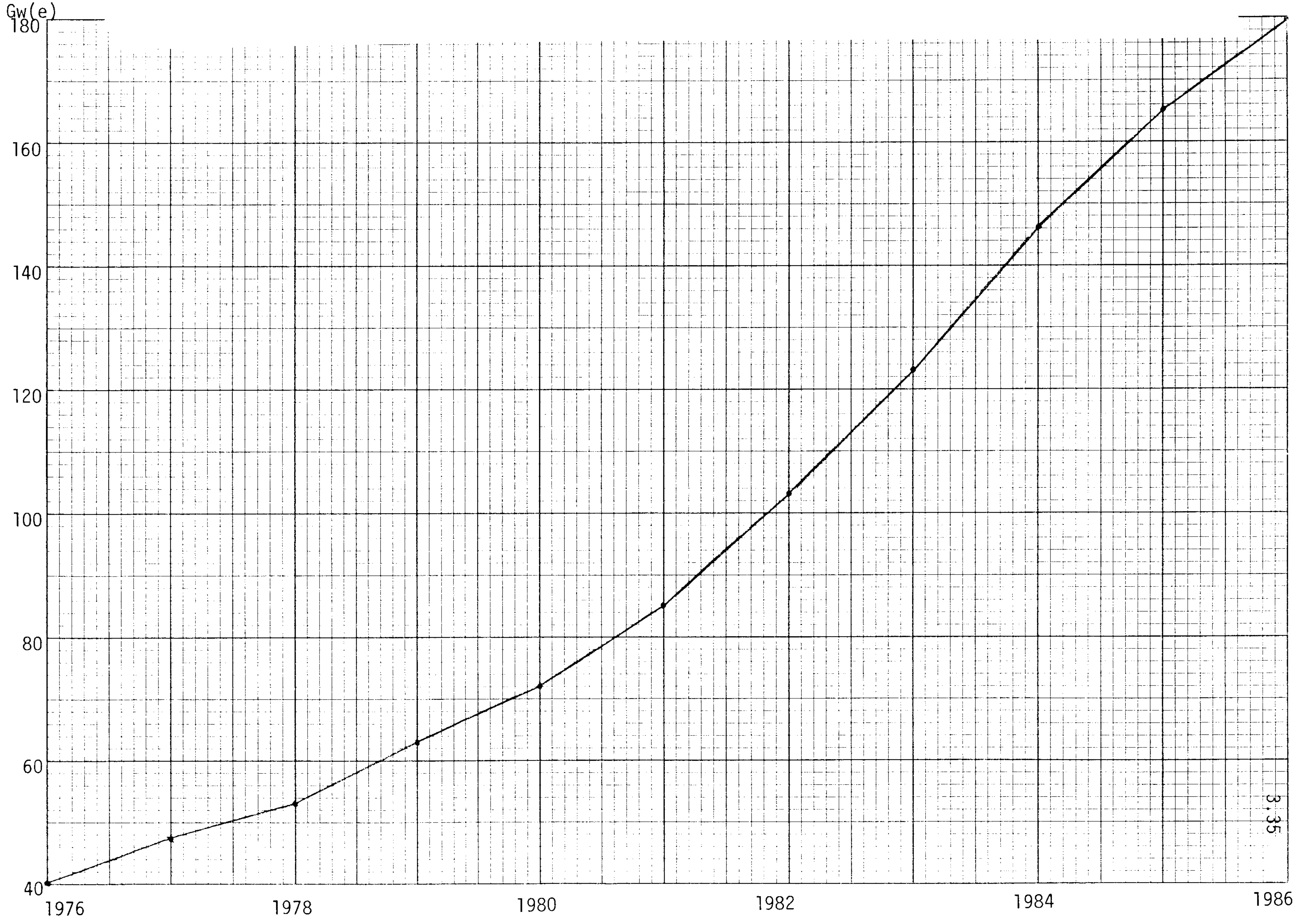
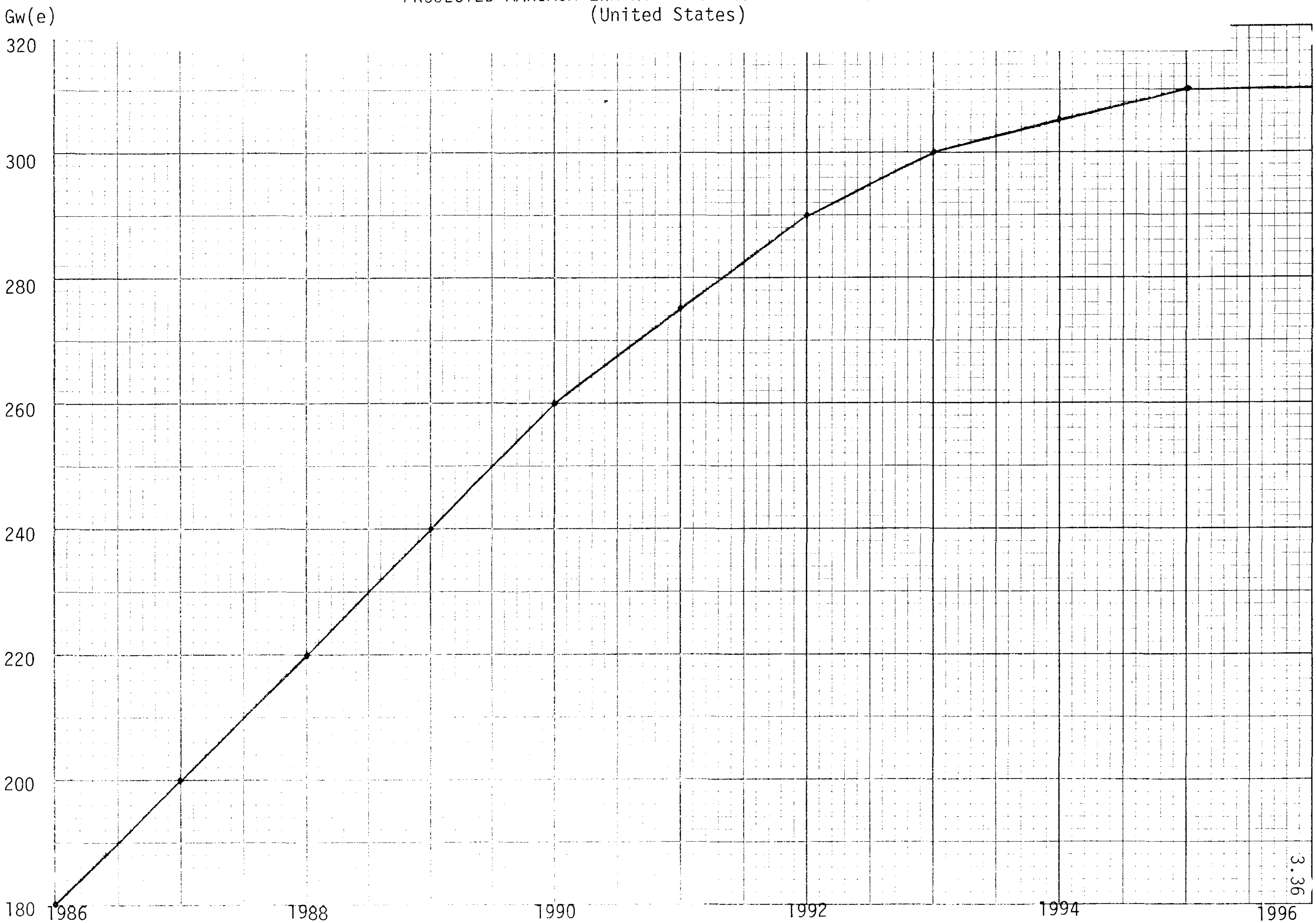


Figure 3.5
PROJECTED MAXIMUM LWR NUCLEAR PLANTS BEYOND 1986
(United States)



uranium supply section. An expected 20,000 Mw(e) would be added each year beyond 1985 until total capacity approached the 310,000 Mw(e) level. The primary reason for limiting the yearly expansion to 20,000 Mw(e) is that nuclear manufacturing capacity could reasonably sustain that level, yet the nuclear vendors would be unwilling to put in more manufacturing capability because of the limited long-term LWR market.

Once the maximum capacity of LWR is defined (as has been done above), the primary influences on uranium, enrichment, and reprocessing/disposal needs are annual capacity factor and enrichment tails assay. To determine maximum demands, the high annual capacity factors (CF) listed below will be used:

Year	CF	Year	CF
1975(actual)	54%	1979	69
1976	60	1980	71
1977	63	1981	73
1978	66	beyond	75

To determine a maximum demand for uranium, the following enrichment tails assay levels will be used:

Year	Tails Assay	Year	Tails Assay
1975(actual)	.20%	1979	.275%
1976	.20%	1980	.275%
1977	.25%	1981	.3%
1978	.25%	beyond	.3%

To determine a maximum demand for enrichment capacity, an enrichment tails assay of 0.2% will be used. In addition, recycle of uranium and plutonium will not be considered in calculating uranium and enrichment demand.

Table 3.16 lists the yearly and cumulative demand for uranium. The table is based on delivery of uranium for the initial core

Table 3.16
MAXIMUM URANIUM DEMAND
(Tons U_3O_8)

Year	Enrichment Assay Factors[a]		Capacity Factor Reload Frac.[b]	Plant (Gw(e)) Reload	Plant (Gw(e)) Initial	Uranium (Tons) Reload[c]	Uranium (Tons) Initial[d]	Total	Yearly Cumulative
1976	5.479	4.697	.276	47.6	10.2	7485	4982	12467	12467
1977	5.965	5.098	.290	53.2	8.3	9570	4400	13970	26437
1978	5.965	5.098	.304	63.4	12.9	11956	6839	18795	45232
1979	6.250	5.333	.317	71.7	18.0	14773	9983	24756	69988
1980	6.250	5.333	.327	84.6	20.3	17980	11258	29238	99226
1981	6.569	5.596	.336	102.6	22.8	23549	13268	36817	136043
1982	6.569	5.596	.345	122.9	19.4	28965	11290	40255	176298
1983	6.569	5.596	.345	145.7	14.5	34338	8438	42776	219074
1984	6.569	5.596	.345	165.1	20.0	38910	11639	50549	269623
1985	6.569	5.596	.345	179.6	20.0	42328	11639	53967	323590
1986	6.569	5.596	.345	200	20.0	47136	11639	58775	382365
1987	6.569	5.596	.345	220	20.0	51849	11639	63488	445853
1988	6.569	5.596	.345	240	15.0	56563	8729	65292	511145
1989	6.569	5.596	.345	260	15.0	61276	8729	70005	581150
1990	6.569	5.596	.345	275	10.0	64811	5819	70630	651780
1991	6.569	5.596	.345	290	5.0	68347	2910	71257	723037
1992	6.569	5.596	.345	300	5.0	70703	2910	73613	796650
1993	6.569	5.596	.345	305	0	71882	0	71882	868532
1994	6.569	5.596	.345	310	0	73060	0	73060	941592
1995	6.569	5.596	.345	310	0	73060	0	73060	1,014,652

[a] 3%/2.6% = reload/initial core assay factors
[b] Reload Fraction = [(1000*365)/(.32*80*31000)]*CF
[c] Reload = 2.5998*(80,000/2000)*reload assay factor*reload fraction*reload Gw(e)
[d] Initial = 2.5998*(80,000/2000)*initial assay factor*initial Gw(e)

two years in advance of commercial operation and delivery of uranium for reload one year in advance of the reload. The amount of reload is based on the capacity factor/burn-up of the preceding year.

Table 3.17 lists the yearly and cumulative enrichment demand. Table 3.18 lists the yearly and cumulative spent fuel removed from the reactor based on the previous year's capacity factor/burn-up.

These maximum demands are based on differing assumptions which preclude all three from happening simultaneously. The maximum uranium demand will not occur if the maximum enrichment is contracted since more enrichment means less uranium needed.

The probability that cumulative LWR nuclear plant capacity will track that of figures 3.4 and 3.5 is quite low. Electric utilities are still confronted with capital formation problems; additional regulatory delays (like the recent Court of Appeals ruling that the Nuclear Regulatory Commission is not complying with the National Environmental Protection Act (NEPA) since its Environmental Impact Statement on individual nuclear plants did not include a section on reprocessing and waste disposal), uncertainties in load growth, antinuclear moratoria, labor disputes, and so forth. A more reasonable estimate of cumulative nuclear plant capacity operational is shown in figure 3.6. The "constrained" line indicates delays reducing the number of LWRs operating on January 1, 1986, to 160 Gw(e), with the eventual total number of plants operational amounting to the present on-order level of 208 Gw(e). This constrained case represents a situation in which the discovery rate of uranium does not exceed 40,000 tons U_3O_8 per year, foreign uranium imports are not available, and plutonium/uranium recycle is not allowed.

Table 3.17

MAXIMUM ENRICHMENT DEMAND
(Thousand separative work units)

Year	Capacity Factor Reload	Gw(e) Reload	Gw(e) Initial	Thousand SWU Reload[a]	Thousand SWU Initial[b]	Total	Cumulative
1976	.276	47.6	5.6	4526	1540	6066	6,066
1977	.290	53.2	10.2	5315	2805	8120	14,186
1978	.304	63.4	8.3	6639	2283	8922	23,108
1979	.317	71.7	12.9	7830	3548	11378	34,486
1980	.327	84.6	18.0	9530	4950	14480	48,966
1981	.336	102.6	20.3	11875	5583	17458	66,424
1982	.345	122.9	22.8	14606	6270	20876	87,300
1983	.345	145.7	19.4	17316	5335	22651	109,951
1984	.345	165.1	14.5	19621	3988	23609	133,560
1985	.345	179.6	20.0	21345	5500	26845	160,405
1986	.345	200	20.0	23769	5500	29269	189,674
1987	.345	220	20.0	26146	5500	31646	221,320
1988	.345	240	20.0	28523	5500	34023	255,343
1989	.345	260	15.0	30900	4125	35025	290,368
1990	.345	275	15.0	32683	4125	36808	327,176
1991	.345	290	10.0	34465	2750	37215	364,391
1992	.345	300	5.0	35653	1375	37028	401,419
1993	.345	305	5.0	36248	1375	37623	439,042
1994	.345	310	0	36842	0	36842	475,884
1995	.345	310	0	36842	0	36842	512,726

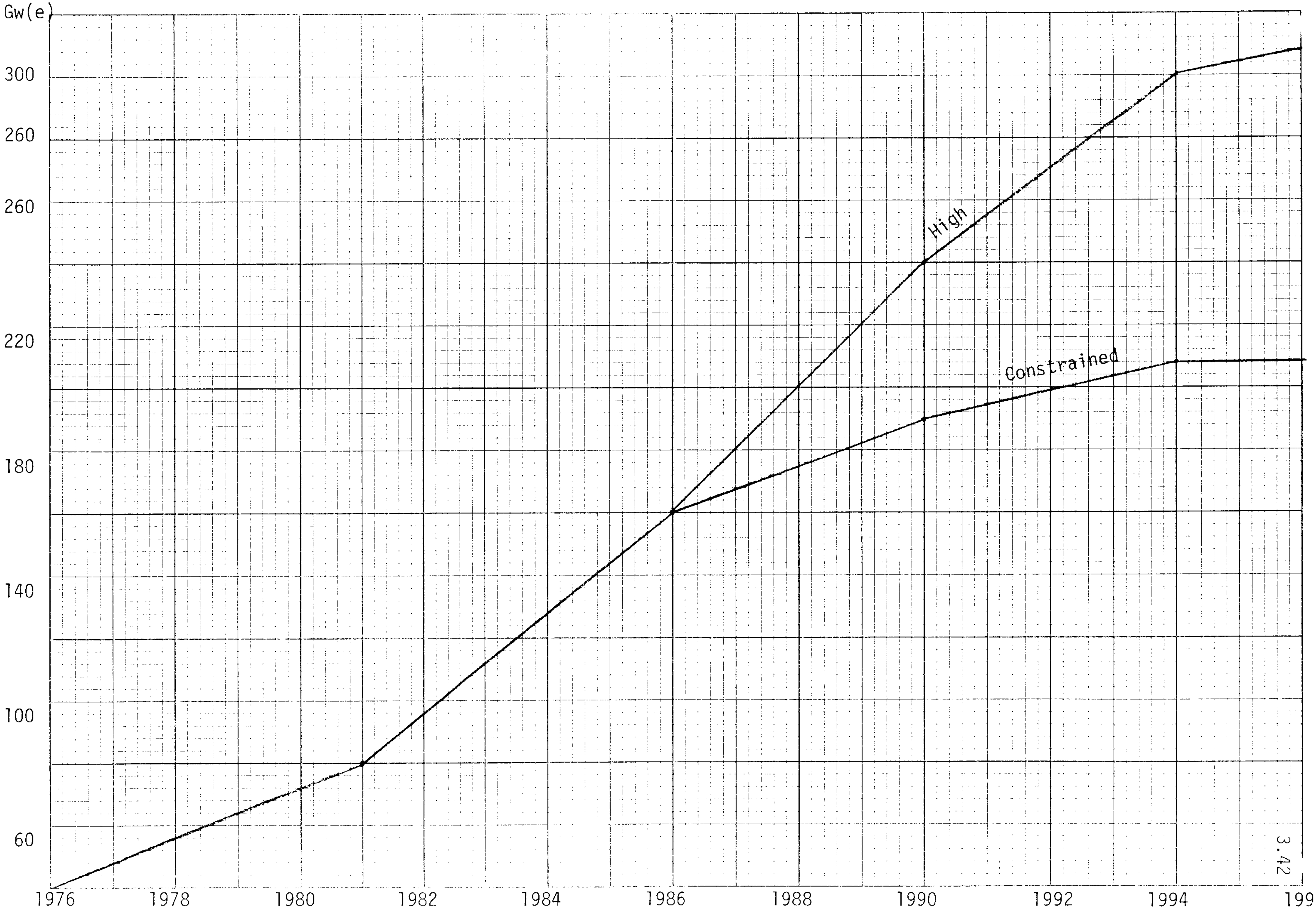
a reload SWU = 4.306 * 80,000 * CF Reload * Reload Gw(e)
b initial SWU = 275,000 * Initial Gw(e)

Table 3.18

MAXIMUM FUEL TO BE REPROCESSED OR DISPOSED OF IN LONG-TERM BURIAL

Year	Capacity Fraction Reload Fraction	Reload Gw(e)	Thousand kg Yearly	Cumulative
1977	.276	47.6	1051	1,051
1978	.290	53.2	1234	2,285
1979	.304	63.4	1542	3,827
1980	.317	71.7	1818	5,645
1981	.327	84.6	2213	7,858
1982	.336	102.6	2758	10,616
1983	.345	122.9	3392	14,008
1984	.345	145.7	4021	18,029
1985	.345	165.1	4557	22,586
1986	.345	179.6	4957	27,543
1987	.345	200	5520	33,063
1988	.345	220	6072	39,135
1989	.345	240	6624	45,759
1990	.345	260	7176	52,935
1991	.345	275	7590	60,525
1992	.345	290	8004	68,529
1993	.345	300	8280	76,809
1994	.345	305	8418	85,227
1995	.345	310	8556	93,783
96	.345	310	8556	102,339

Figure 3.6
LWR NUCLEAR PLANT CAPACITY IN THE UNITED STATES



The "high" line also indicates a certain number of delays through 1986 as in the "constrained" case; however, sufficient uranium reserves are assumed to be developed to justify an expansion of commitment to LWR nuclear power plants up to 310 Gw(e).

Texas Demand

Table 3.19 lists the in-state nuclear plants planned for Texas and the out-of-state nuclear plants which might provide power to consumers within Texas. All of the power from plants built within Texas will serve Texas consumers. The two River Bend units of Gulf States Utilities will probably supply some power to Texas until the Blue Hills units come on line since Gulf States Utilities attempts to build sufficient generating facilities in each state to meet the loads of their service area within each state. El Paso Electric owns a 17% share of the Palo Verde nuclear plant. Since 70% of El Paso Electric's consumption is in Texas, 136 Mw(e) (1240 x .17 x .70) from each unit will likely be available to Texas consumers.

The Black Fox nuclear plant in Oklahoma is 70% owned by Public Service of Oklahoma (PSO), which is controlled by Central and Southwest Corporation. Central and Southwest also controls Southwestern Electric Power (SWEPCO), which serves the northeast corner of Texas; West Texas Utilities (WTU) which serves the midwestern portion of Texas; and Central Power and Light (CPL) which serves the southern part of Texas. Power from PSO's Black Fox plant could be transmitted to SWEPCO for use in Texas through existing ties between the companies. If the present interties in North Texas are maintained between the Southwest Power Pool and the Electric Reliability Council of Texas pool, power from PSO's

TABLE 3.19

LWR NUCLEAR PLANTS IN TEXAS ON AFFECTING TEXAS CONSUMERS

PLANT	UTILITY	TYPE	OUTPUT Mw(e) Net	COMMERCIAL OPERATION DATE
Comanche Peak 1	Texas Utilities	PWR-W	1150	1981
South Texas Nuclear 1	Houston L&P,others	PWR-W	1250	1981
Comanche Peak 2	Texas Utilities	PWR-W	1150	1982
South Texas Nuclear 2	Houston L&P,others	PWR-W	1250	1982
Allens Creek	Houston L&P	BWR-GE	1150	1986
Blue Hills 1	Gulf States Util.	PWR-Comb	920	1989
Blue Hills 2	Gulf States Util.	PWR-Comb	920	1991
			7790	
OUT-OF-STATE				
River Bend 1	Gulf States Util.	BWR-GE	935 (374)	1981
River Bend 2	Gulf States Util.	BWR-GE	935 (374)	1983
	(Located in Louisiana)	(Power to Texas until 1989)		
Palo Verde 1	El Paso Elec.	PWR-Comb	1240 (136)	1982
Palo Verde 2	El Paso Elec.	PWR-Comb	1240 (136)	1984
Palo Verde 3	El Paso Elec.	PWR-Comb	1240 (136)	1986
	(Located in Arizona)	(EPE owns 17% with 70% used in Texas)		
Black Fox 1	P.S. of Okla.	BWR-GE	1150	1983
Black Fox 2	P.S. of Okla.	BWR-GE	1150	1985

(Located in Oklahoma) (Central & Southwest Corporation is the holding company for P.S. of Oklahoma, West Texas Utilities, Central Power & Light, and Southwestern Electric Power; therefore, some power might be allocated to its utilities within Texas.)

Black Fox plant could be transmitted to WTU and CPL. However, the level of power shipped to Texas from the Black Fox plant is uncertain and at best will only amount to a couple of hundred megawatts.

In the event that the nation's utilities make a high level of commitment to nuclear power (figures 3.4, 3.5, and 3.6), approximately 100 Gw(e) of additional capacity would be available nationally. Of the 100 Gw(e), major regions could be expected to receive roughly the following increments:

1. New York Power Pool - 12 Gw(e)
2. California - 15 Gw(e)
3. Delaware, Maryland, Virginia - 8 Gw(e)
4. Louisiana, Mississippi, Alabama - 10 Gw(e)
5. Florida - 8 Gw(e)
6. Texas - 12 Gw(e)
7. Rest of U.S. - 40 Gw(e)

California, New York, Florida, Delaware, Maryland, and Virginia are somewhat dependent on fuel oil, have pollution problems, or may not be able to use as much coal as needed; therefore, they will likely order additional nuclear plants. Louisiana, Mississippi, Alabama, and Texas are fast-growing industrial areas with a large dependence on fuel oil or gas; therefore, they will likely order nuclear plants to meet large growing energy needs. Four areas which may be saturated with delayed nuclear projects or a high percentage of nuclear, and which may not have an incentive for additional nuclear plants are the Carolinas, TVA, Illinois, and New England. The rest of the nation should account for 40 Gw(e), especially the Pacific Northwest, Great Plains, and industrial Midwest.

Figure 3.7 illustrates the planned LWR nuclear power plant capacity available to customers in Texas and the maximum possible power capacity available.

Based on the same assumptions as for the national demand, the maximum expected demand for uranium, enrichment, and reprocessing/disposal due to Texas consumers is listed in tables 3.20, 3.21, and 3.22.

Figure 3.7
LWR NUCLEAR PLANT CAPACITY FOR TEXAS

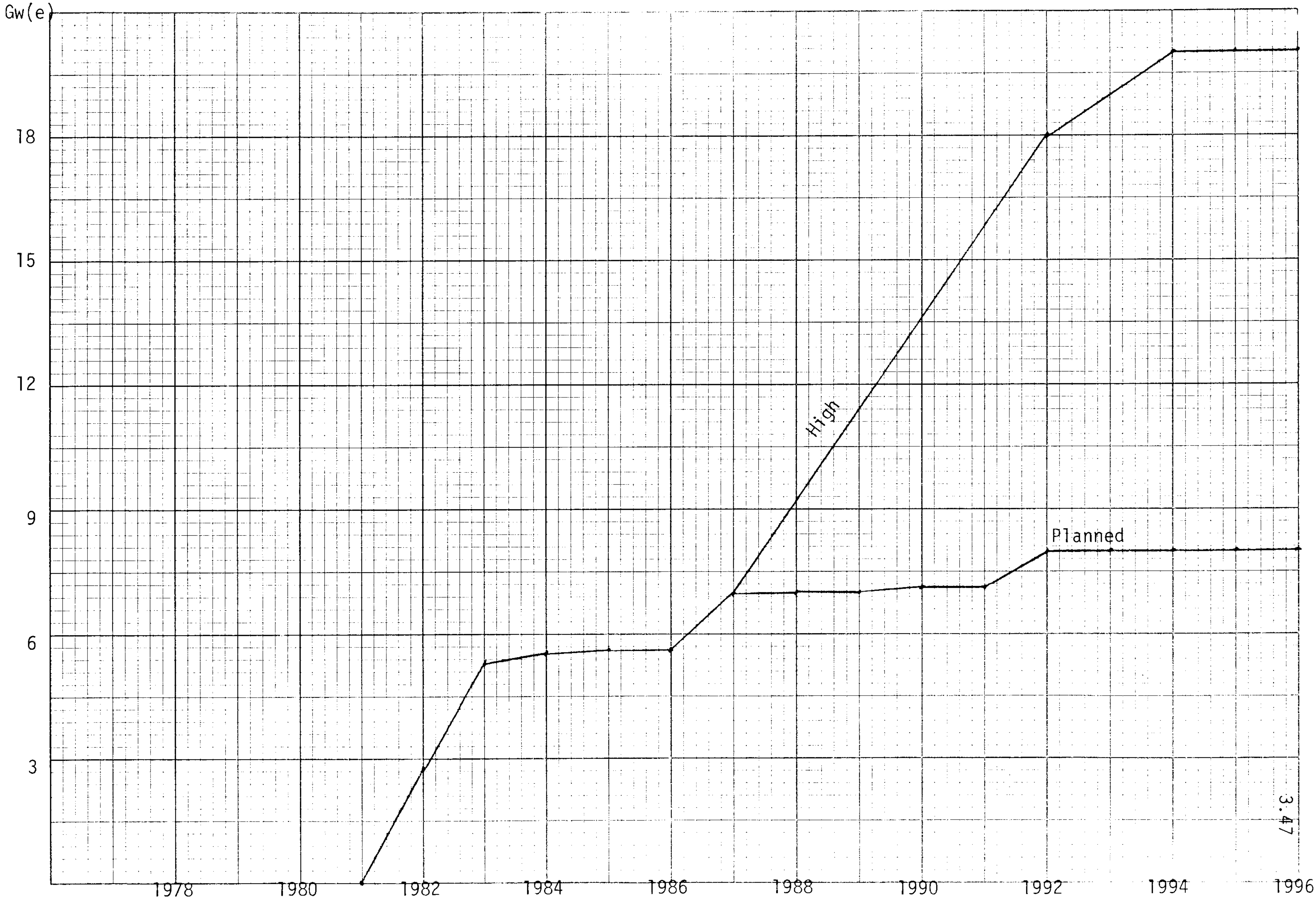


TABLE 3.20

MAXIMUM URANIUM DEMAND FOR TEXAS
(Tons U_3O_8)

Year	Plant Reload	Initial	Uranium Reload[a] (Tons)	Initial[b]	Yearly Total	Cumulative
1979		2.774	-	1614.3	1614.3	6141.3
1980		2.536	-	1475.8	1475.8	3090.1
1981	2.774	.374	653.8	217.6	871.4	3961.5
1982	5.310	.136	1251.4	79.1	1330.5	5292.0
1983	5.684	-	1339.6	-	1339.6	6631.6
1984	5.820	1.286	1371.6	748.4	2120.0	8751.6
1985	5.820	2.179	1371.6	1268.0	2639.6	11,391.2
1986	7.106	2.179	1674.7	1268.0	2942.7	14,333.9
1987	9.285	2.179	2188.3	1268.0	3456.3	17,790.2
1988	11.464	2.178	2701.8	1268.0	3969.8	21,760.0
1989	13.643	2.179	3215.3	1268.0	4483.3	26,243.3
1990	15.821	1.000	3728.7	581.9	4310.6	30,553.9
1991	18.000	1.000	4242.2	581.9	4824.1	35,378.0
1992	19.000	-	4477.9	-	4477.9	39,855.9
1993	20.000	-	4713.6	-	4713.6	44,569.5
1994	20.000	-	4713.6	-	4713.6	49,283.1
1995	20.000	-	4713.6	-	4713.6	53,996.7

[a]Reload = 2.5998 * (80,000/2,000) * 6.569 * .345 * reload Gw(e)

[b]Initial = 2.5998 * (80,000/2,000) * 5.596 * initial Gw(e)

TABLE 3.21

MAXIMUM ENRICHMENT DEMAND FOR TEXAS
(Thousand Separative Work Units)

Year	Plant Reload (Gw(e))	Initial	Enrichment Reload[a]	Initial[b]	Yearly Total	Cumulative
1980	-	2.774	-	762.9	762.9	762.9
1981	2.774	2.536	329.7	697.4	1027.1	1790.0
1982	5.310	.374	631.1	102.9	1634.0	3424.0
1983	5.684	.136	675.5	37.4	1012.9	4436.9
1984	5.820	-	691.7	-	691.7	5128.6
1985	5.820	1.286	691.7	353.7	1045.4	6174.0
1986	7.106	2.179	844.5	599.2	1443.7	7617.7
1987	9.285	2.179	1103.5	599.2	1702.7	9320.4
1988	11.464	2.179	1362.4	599.2	1961.6	11,282.0
1989	13.643	2.178	1621.4	599.2	2220.6	13,502.6
1990	15.821	2.179	1880.3	599.2	2479.5	15,982.1
1991	18.000	1.000	2139.2	275.0	2414.2	18.396.3
1992	19.000	1.000	2258.1	275.0	2533.1	20,929.4
1993	20.000	-	2376.9	-	2376.9	23,306.3
1994	20.000	-	2376.9	-	2376.9	25,683.2
1995	20.000	-	2376.9	-	2376.9	28,060.1

[a]Reload SWU = 4.306 * 80,000 * .345 * Reload Gw(e)

[b]Initial SWU = 275,000 * Initial Gw(e)

TABLE 3.22

MAXIMUM FUEL TO BE REPROCESSED OR DISPOSED OF IN LONG-TERM BURIAL IN TEXAS
(Metric Tons Uranium)

Year	Reload Gw(e)	Yearly[a]	Cumulative
1982	2.774	76.6	76.6
1983	5.310	146.6	223.2
1984	5.684	156.9	380.o
1985	5.820	160.6	540.7
1986	5.820	160.6	701.3
1987	7.106	196.1	897.4
1988	9.285	256.3	1153.7
1989	11.464	316.4	1470.1
1990	13.643	376.5	1846.6
1991	15.821	436.7	2283.3
1992	18.000	496.8	2780.1
1993	19.000	524.4	3304.5
1994	20.000	552.0	3856.5
1995	20.000	552.0	4408.5
1996	20.000	552.0	4960.5

[a]Yearly = .345 * 80. * Reload Gw(e)

3.3.2 Uranium Supply

Great confusion exists outside the nuclear industry about the adequacy of uranium supply for the various LWR nuclear plants across the nation. To put the discussion of uranium supply in perspective, a summary of tables 3.16 and 3.20 is listed in table 3.23. The maximum demands are based on a high capacity factor of 75%, a burn-up of 31,000 Mwd/MTU, an enrichment tails assay of 0.3%, no plutonium or uranium recycle, and a fast buildup of planned nuclear plants. If one were to factor in delays and normal capacity factors, a more reasonable assessment would be that actual demand would equal about 80% of maximum demand. For comparative purposes between supply and demand, this section will use maximum demands as a conservative measure.

How do the reserves and resource base compare to the above demands? The estimate of U_3O_8 at a production cost of $30 or less amounts to:

a) 640,000 tons of reserves in conventional sandstone deposits

b) 140,000 tons recoverable as a by-product of phosphate and copper production during the period 1976-2000

c) 1,060,000 tons probable reserves

d) 1,270,000 tons possible reserves, and

e) 590,000 tons speculative reserves [1]

It is likely that estimates of resources in conventional sandstone-type deposits (which contain the majority of present reserves) will increase as a result of future exploration [1].

A prudent method of planning the amount of uranium available to the nuclear power industry would be to consider only proved and probable reserves. Based on a total of 1,840,000 tons of U_3O_8, the amount of

Table 3.23

MAXIMUM U.S. AND TEXAS URANIUM DEMAND (SUMMARY)
(Tons U_3O_8)

U.S.	Yearly	Cumulative
1980	29,238	99,226
1985	53,967	323,590
steady state 208 Gw(e)	49,000	
1990	70,630	651,780
1995	73,060	1,014,652
steady state 308 Gw(e)	73,000	
Texas		
1980	1,476	3,090
1985	2,640	11,391
steady state 8 Gw(e)	1,910	
1990	4,310	30,554
1995	4,714	53,997
steady state 20 Gw(e)	4,714	

uranium from domestic sources available for a 30-year steady state demand would be 61,300 tons per year. Assuming that domestic sources were supplying 85% of demand, the total maximum uranium available per year would be about 70,000 tons. Thus, based on proven and possible reserves, a cumulative commitment to LWR nuclear plants amounting to 300 Gw(e) could be justified.

But can the reserves and resources be developed on a timely basis? A recent survey of the uranium industry indicated that production would rise to 24,300 tons U_3O_8 by 1980 [2]. The estimate was "entirely based on ore bodies known today and mainly keyed to existing reserves and is subject to revision as exploration effort proceeds." It appears that domestic production capacity planned for 1980 will be able to meet <u>at least</u> 80% of the maximum possible demand of 29,000 tons in 1980.

Can the uranium industry expand its production capacity to a level as high as 61,000 tons per year in a short period of time from the 1975 level of 14,500 tons per year [2]? Historically, uranium production in the United States increased from 880 tons in 1952 to its maximum output of 17,640 tons in 1960 [3]. In a broader sense, many mineral industries have sustained high growth rates over several decades. The net growth over the 20-year maximum growth period (domestic) for crude petroleum, molybdenum, copper, and coal was 202, 291, 336, and 168% respectively [3]. The needed growth from today's level to 1995's 60,000 ton capacity (about 300% net growth) to support 300 Gw(e) of LWR nuclear plants appears to be possible.

The most critical phase of the uranium mining and milling industry at present centers on the level of exploration. It takes approximately

10 years to find, define, and bring to full production new bodies of ore. For the commitment to nuclear power to grow, enough reserves must be discovered each year to offset production during that year plus increase the proven reserves remaining. If during a given year production was equal to 1/20 of proven reserves, then present reserves could support 32,000 tons of production. A reserve of 1,400,000 tons would be required by 1990 to support 70,000 tons per year production.

To allow a 50% increase in commitments to nuclear plants based only on domestic reserves, exploration must prove up the cumulative consumption between now and 1990 (a maximum of 650,000 tons U_3O_8) and expand the total remaining proven reserves to 1,400,000 tons. The total reserves needed to be found amount to approximately 1,250,000 tons over the next 15 years, or an average of about 80,000 tons per year. With foreign sources supplying approximately 20% of demand, only 840,000 tons would need to be found, or 56,000 tons per year.

The level of exploration drilling has hovered around 20,000,000 feet per year during the last few years with a discovery rate between one and two pounds U_3O_8 per foot drilled. This past level of exploration is insufficient to support expansion beyond the present 208 Gw(e) level of LWR nuclear plant commitments; however, technological changes in the method of exploring for uranium (such as sniffing for helium) could drastically change the level of discovery. The level of conventional exploration has been increased substantially in 1976, but the results of the increase are not yet known. The above discussions were limited to domestic reserves and production, which historically have been for domestic use. In addition to the domestic sources, imports primarily from Canada have supplied a small but significant portion of the overall demand. Present uranium import commitments by domestic buyers average 3,000 tons U_3O_8 per year to 1990 [4].

With the present tight supply situation domestically, what is the availability of foreign supplied uranium? The present U_3O_8 resources in Australia, recoverable at costs of up to $15.00 per pound, are estimated at about 331,000 tons [5]. Of this amount less than 10,000 tons is committed. The six major potential Australian uranium producers have the capability of increasing production by 15,000 to 20,000 tons by the early 1980s [5].

Canada has already committed 110,000 tons U_3O_8 for export and has reserved 81,000 tons to cover the 30-year fueling requirements for the 14,700 Mw(e) of nuclear capacity expected to be operating in Canada by 1986 [6]. Canada's presently measured, indicated, and inferred resources, recoverable at costs less than $40 per pound, amount to 562,400 tons U_3O_8 [6]. In addition, "prognosticated" resources in and adjacent to minable deposits based on extrapolated geological information amount to 450,000 tons [6].

Thus sizable amounts of uncommitted reserves are available in Canada and Australia. The United States should be able to contract for up to 10,000 tons per year from these two countries alone by the mid 1980s even with other nations bidding for supplies. Additional exploration activities throughout the world could bring in significant quantities of U_3O_8 from areas with high potential such as the Moroccan Sahara.

One unusual but significant difference between nuclear fission and fossil fuels is that consumption of the raw material, U_3O_8, can be reduced without reducing power output simply by modifying the nuclear fuel cycle. By reducing the enrichment tails assay from 0.3% to 0.2%, U_3O_8 requirements are reduced by 16.6%. By recycling the uranium and plutonium from spent fuel assemblies, the steady state U_3O_8 requirements can be reduced by another 30%. The steady state requirements of 300 Gw(e) of LWR nuclear power plants would be reduced to 41,000 tons U_3O_8 per year (70,000 * .834 * .70) with the two modifications to the nuclear fuel cycle.

Texas Uranium Supply

Uranium is a highly transportable fuel with large energy output for a small volume of material; thus, there is little connection between the region of uranium production and the region of consumption. Presently, all uranium which is produced in Texas is consumed elsewhere. For future supplies of uranium the major in-state utilities are exploring in New Mexico. Notwithstanding the above, a brief look at uranium resources and production within Texas would indicate whether Texas is maintaining a net balance between production and consumption.

The primary uranium resources in Texas are located in the coastal plain which extends from Texas to New Jersey. Of this region most of the resources lie with Texas. The amount of resources in Texas producible at costs of $30 per pound U_3O_8 are approximately 40,000 tons proved; 100,000 tons probable; 125,000 tons possible; and 30,000 tons speculative reserves [1]. The total proved and probable reserves are roughly 2-1/2 times the cumulative maximum demand of in-state utilities through 1995 (table 3.20). In effect the proved and probable uranium reserves in Texas exceed the cumulative expected demands through the year 2010.

Conclusions - Uranium Resource Base and Its Availability

With orderly development of today's domestic proved reserves, about 80% of the maximum demand in 1980 can be met and 60% of the maximum demand in 1985 can be met. The present level of foreign supply commitments will meet about 10% of maximum 1980 demand and 6% of maximum 1985 demand. Thus, the level of supply of uranium for a maximum demand in 1985 is more assured than the supply of either natural gas or oil. By 1985 today's proven reserves of natural gas will supply less than 40% of normal demand, while today's proven reserves of crude oil will supply less than 33% of normal demand.

The present level of exploration should provide the additional reserves and production capacity to cover the remaining demand in 1985. Therefore, the present level of nuclear plant commitment within Texas based on resource base and availability appears to be reasonable, especially in light of the tight supply situation with natural gas and crude oil.

The domestic nuclear plant commitment level could be expanded by 50% or about 100 Gw(e), if the level of exploration were stepped up by a factor of 100% and/or if foreign sources of uranium were aggressively pursued.

The above conclusions are conservative, since the resource base and availability could expand significantly as a result of new exploration technology and extraction processes and since the nuclear fuel cycle may be modified to include recycle and a lower tails assay.

REFERENCES TO SECTION 3.3.2

1. National Uranium Resource Evaluation Preliminary Report, GJO-111(76), U.S. Energy Research and Development Administration, June 1976.

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3. Statement of George F. Quinn, Atomic Energy Commission, "Future Structure of the Uranium Enrichment Industry," Hearings before Joint Committee on Atomic Energy, Congress of the United States, July 31, 1973.

4. Survey of United States Uranium Marketing Activity, ERDA 76-46, U.S. Energy Research and Development Administration, April 1976.

5. Australia's Uranium Resources, Australian Uranium Producer's Forum, May 1976.

6. 1975 Assessment of Canada's Uranium Supply and Demand, Canadian Department of Energy, Mines, and Resources, May 1976.

3.3.3 Nuclear Fuel Cycle Costs

Determining a fuel cost for LWR nuclear power plants is an order of magnitude more difficult than for fossil fuel plants. Typically for oil, gas, or coal the utility pays for the fuel at the time of delivery and then immediately consumes the fuel (reserve storage is treated as a separate capital cost). At most the utility would have two bills for the fuel: one for mining and production into a usable form and the second for transportation to the site. Although with coal there is a small cost for disposing of the waste, that charge is incurred immediately after burning.

Nuclear fuel costs, on the other hand, encompass many separate charges. Since uranium in its natural state is unsuitable for use in an LWR, major processing and fabrication are required over a period of 12 to 18 months. The electric utility normally pays for mining, purification and conversion, enriching, and fabrication to separate business concerns. The nuclear fuel is then "burned" over a period of 36 to 48 months, during which time the utility incurs carrying charges. Finally, after the nuclear fuel has been consumed, there are significant delayed charges for transporting and disposing of the fuel assemblies.

This section discusses the costs associated with each phase of the nuclear fuel cycle and the time charges associated with each phase. For the remainder of this discussion the cost of money will be assumed to be 9% on a short-term basis, and inflation will be compounded at a 7% rate.

The nuclear fuel cycle is described in table 3.25. The analysis assumes that a) reprocessing of spent fuel assemblies does not exist because of either government decision or the costs of reprocessing and mixed oxide fabrication facilities, b) the "throw away" fuel cycle is used, c) LWR plants operate at 66% capacity factor, d) the fuel assemblies achieve a steady state burn-up of 31,000 Mwd/MTU, and e) the enrichment tails assay is maintained at 0.3%.

The nuclear fuel cycle costs will be discussed in terms of the average cost for each phase for purposes of calculating within the economic model the price/demand relationships and elasticities and in terms of each phase's incremental cost for purposes of determining whether a utility would build an additional nuclear unit versus the other alternatives.

Uranium

The market price for uranium has been buffeted high and low by many unusual circumstances. The circumstances can be broken down into four main areas.

Normal pricing has been disrupted due to the historical development of the uranium industry. The original uranium mining industry's development was tied exclusively to the national nuclear weapon's program. The industry's output grew to 18,000 tons of U_3O_8 per year by 1960 but then the U.S. government phased out its buying program. Thus there existed an entire mature industry without a significant market for its product. Prices for uranium delivered and contracted in the late 1960s and early 1970s plummeted to the producer's cost of mining their highest grade ores. Since most of the industry's facilities had been amortized under the weapons buying program there were no capital charges included in the

Table 3.25

NUCLEAR FUEL CYCLE

Item	Timing[a] (months)
U_3O_8 Supply	15
Purification/Conversion	12
Enrichment	10 (0.3% tails)
Fabrication	4
Power Production	0-40[b]
Shipment of Spent Fuel	64
Waste Disposal	66

[a] Timing is based on a May refueling which ends with a June 1 cycle startup.

[b] Although fuel is loaded only once a year, some fuel assemblies may remain in the reactor for 4 years while others only 3 years, giving a fractional cycle result. The above 3-1/3 year cycle is based on a 66% capacity factor and a burn-up of 31,000 Mwd/MTU.

price [1]. Since uranium demand was low, little exploration was undertaken thus adding no incentive component to the low uranium price hovering around \$6 to \$8 [1]. In addition in 1973-75 as future demand for uranium started to come in balance with supply, i.e. the needs of an expanding commercial nuclear power program started approaching the maximum output of the "old" uranium industry, the price for the major competing fuels, oil and coal, exploded upward placing additional upward pressure on uranium prices.

A second disruption to the uranium market is inherent in the nature of the industry itself. The uranium mining industry requires large amounts of funds for exploratory drilling. The industry typically has funded exploration from present revenues due to the long lead time before new discoveries can start producing. Yet during the late 1960s and early 1970s the price of uranium was depressed because of a short term over capacity in the industry. Much of the uranium to be delivered through 1980 is priced at production costs (including inflation) since the contracts were signed during the early 1970s. As a result, the price of the majority of uranium committed to date does not provide sufficient funds to support an extensive exploration effort. The uranium mining industry has taken two approaches. Prices for short term delivery have risen sufficiently high to provide those suppliers, who have had recent sales, funds to increase their exploration. Other uranium producers have formed joint ventures with utility customers so that adequate funds are available for exploration and development. Ranchers Exploration/Texas Utilities and Continental Oil/Houston Lighting and Power are two examples of joint ventures.

A third disruption to the market was the uncertainty in the level of supply. In the early 1970s the U.S. government had a stockpile of 50,000 tons of U_3O_8 which could meet about four years of demand by the utility industry. Foreign suppliers had an excess production capacity of 50% in the early 1970s as worldwide demand for uranium for nuclear weapons dropped. Canada and Australia had large supplies of uranium which were uncommitted. Domestic producers were uncertain as to whether they should expand their production capacity or prepare for a glut of additional uranium in the market. By 1975, the U.S. government had decided to use its uranium stockpile to build up a reserve of enriched uranium and had decided to restrict the use of foreign uranium until the late 1970s. In addition the Australian and Canadian governments placed a temporary moratorium on uranium sales. The domestic producers should have started developing expanded production capacity at an earlier date since the expected glut in uranium supply did not materialize.

The final disruption to the market was and continues to be the uncertainty of demand. The early nuclear program (1960s) was supposed to take off exponentially but didn't. Then in 1972, 1973, and early 1974 reactor sales exploded upward spurred on by increasing oil costs. Then the financial crisis of 1974-1975 and lack of load growth caused nuclear plant delays and cancellations. The effect has been to disrupt the producer's ability to plan for future demand, estimates of which have swung by as much as 50%. Indecision by the U.S. government on enrichment capacity expansion and recycle have led to another 40% uncertainty in demand. The threat of spreading state moratoriums have made producers leery of long term investments to expand production capacity which might not be recovered. Finally a major "middle man"--Westinghouse sold short on uranium and was not able to cover its commitments. The 25,000 ton U_3O_8 shortage produced an immediate 50% to 100% increase in demand in the market through 1980.

Today the uranium marketplace exhibits greater stability and less volatility than at any other time during the last three years. As the commercial nuclear industry has started to mature the demand has come more in line with supply resulting in uranium prices rising to a more normal level from their depressed level of several years ago. Electric utilities have concluded that domestic producers will have to supply the majority of uranium in the foreseeable future and that there are no giant stockpiles lying around. Recycle and lowered enrichment tails will not have any effect before 1985 if at all. Even on a short term supply basis the uranium market has shown stability at around $40 per pound [2].

Proceeding on the basis that in the future the uranium market will be orderly, projected prices for two sets of conditions will be determined: one projected price for the yearly average delivered price, the second projected price for the incremental amount of uranium for one additional nuclear unit. The actual average delivered uranium price through 1980 will be somewhat depressed due to the contracts signed in the late 1960s and early 1970s under the previously discussed abnormal conditions [4].

This analysis also assumes that 50% of the probable domestic reserves are discovered by 1985 and 100% by 1990 but that no possible or speculative reserves are discovered. Table 3.26 lists the reserves in the differing cost categories [3]. Table 3.16 will be used to determine the cumulative uranium delivered up to the year under consideration.

For the projected incremental price, cumulative uranium commitments will be assumed to include the cumulative demand up to the year under consideration (table 3.16) plus a ten year steady state reserve for units already operating in the year under consideration. For the projected average and incremental price calculations, the previously used or committed uranium will be assumed to have come from the lowest available cost category. The price will include the uranium production costs from table 3.26, profit, exploration incentive, and shipping costs to the conversion plant. Rather than go through a lengthy series of guesses about the latter three costs, the projected prices will be considered to be double the production cost.

Table 3.27 lists the projected average and incremental uranium price. Where the majority of uranium available in a certain cost category (table 3.26) was already delivered or delivered plus committed, the next higher cost category was used. In reality many mines would be working from lower grade, higher cost formations even with some higher grade ores still available.

Figures 3.8, 3.9, 3.10, and 3.11 show the projected price trends including the effects of inflation rate and the movement to higher cost production of lower grades of ore. There are large uncertainties within these price projections.

a) Large additional reserves could be discovered which would invalidate the analysis

b) Advanced production methods such as leaching might significantly lower some production costs.

Table 3.26

URANIUM RESERVES BY COST CATEGORY
(Tons U_3O_8 - 1975 dollars)

Cost ($/lb)	1976	1985	1990[a]
<$10	270,000	490,000	710,000
10-15	160,000	267,000	375,000
15-30	210,000	413,000	615,000
TOTAL[b]	640,000	1,170,000	1,700,000

[a]is not reduced for uranium produced to that time.

[b]does not include an estimated 140,000 tons U_3O_8 recoverable as a by-product of phosphate and copper production.

Table 3.27

PROJECTED URANIUM PRICE
(Dollars per pound U_3O_8)

Projected Average Price:	1976	1980	1985	1990	1995	2000
Nuclear Plants Operational (Gw(e))	47.6	84.6	180	275	310	310
Cumulative Production (tons)	12,467	99,226	323,590	651,780	1,014,652	1,400,000
Cost Category	<10	<10	10-15	10-15	15-30	15-30
Price (1975 $)	<20	<20	20-30	20-30	30-60	30-60
Current Dollars	<20	<28	39-59	55-83	116-232	163-326
Projected Incremental Price:						
Cumulative Production plus 10 yr. (tons)	87,317	279,026	746,870	1,299,890	1,745,252	2,310,552
Cost Category	<10	10-15	15-30	15-30	30+	-
Price (1975 $)	<20	20-30	30-60	30-60+	60+	-
Current Dollars	<20	28-42	59-118	83-166	232+	-

Figure 3.8

PROJECTED 1976-1985 AVERAGE URANIUM PRICE
(Current Dollars per pound U_3O_8)

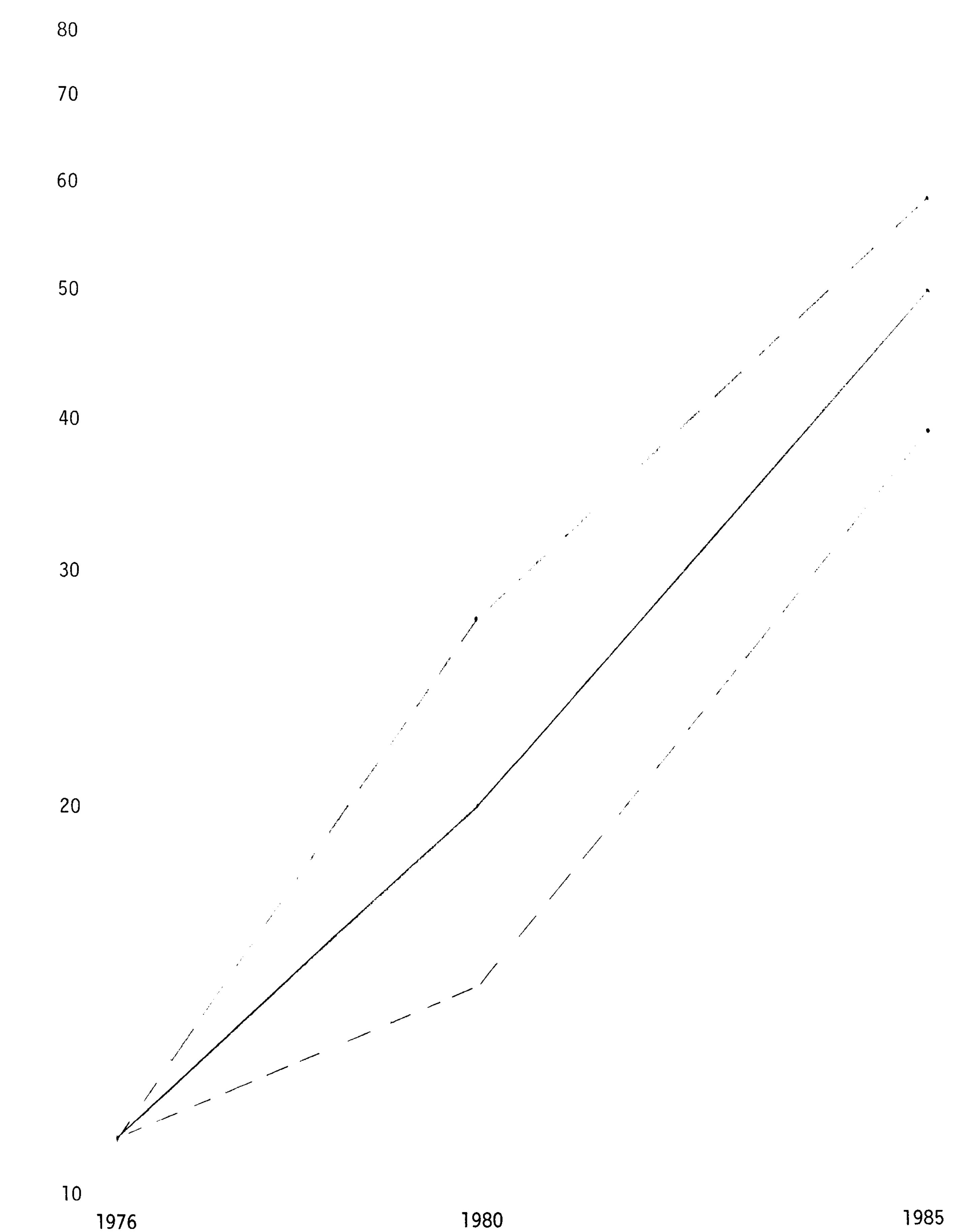


Figure 3.9

PROJECTED 1985-1995 AVERAGE URANIUM PRICE
(Current dollars per pound U_3O_8)

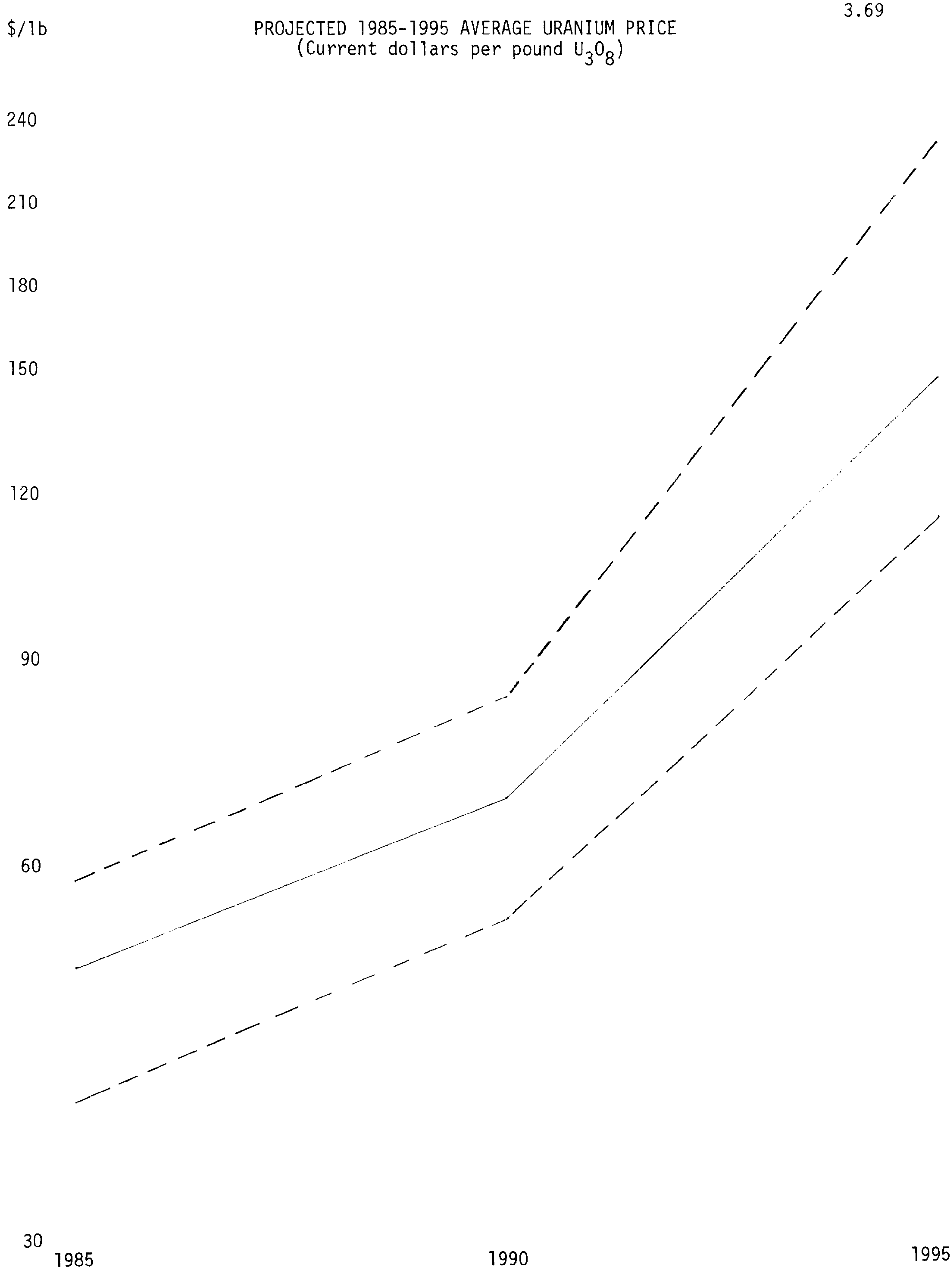


Figure 3.10

PROJECTED 1976-1985 INCREMENTAL URANIUM PRICE
(Current dollars per pound U_3O_8)

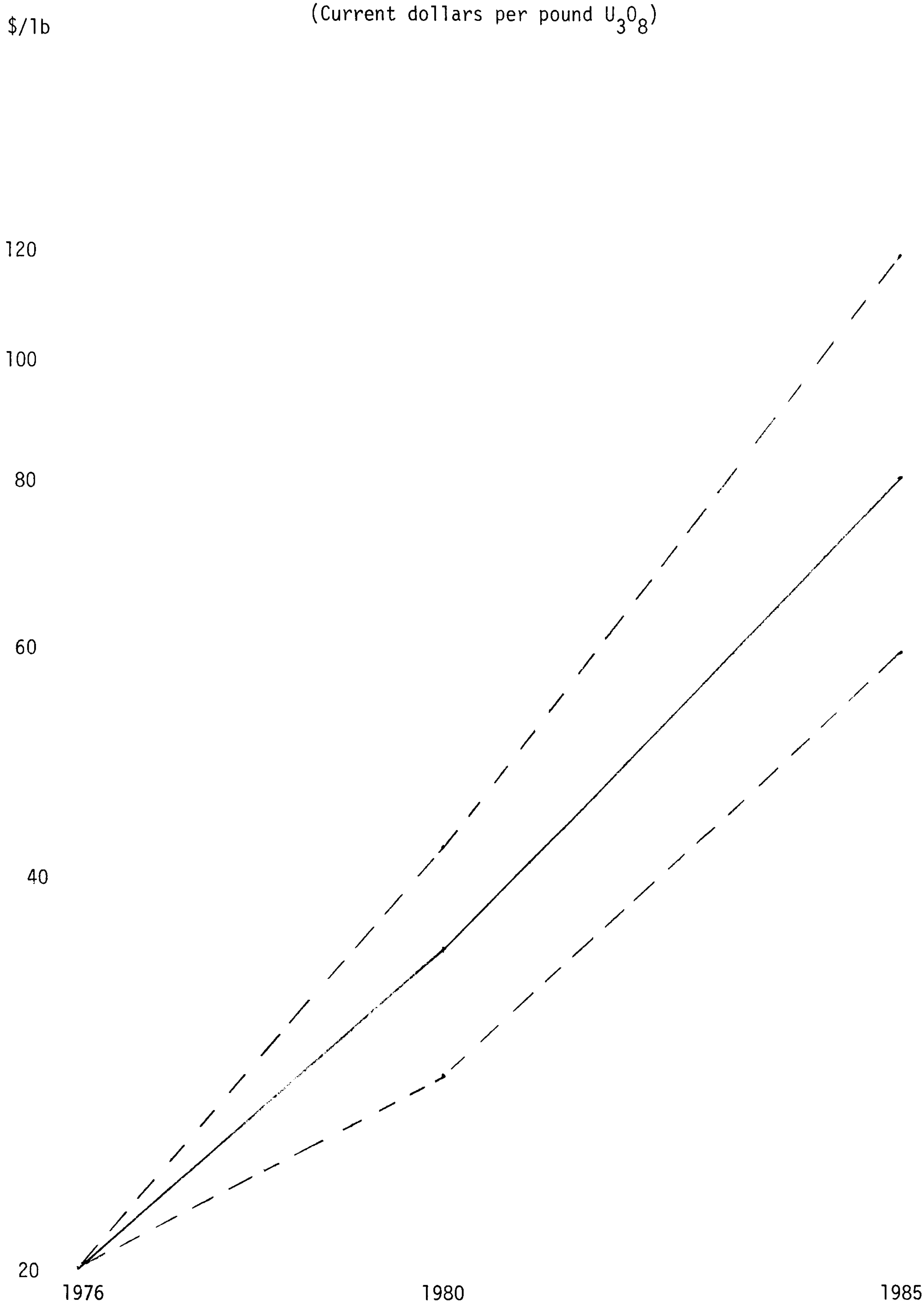
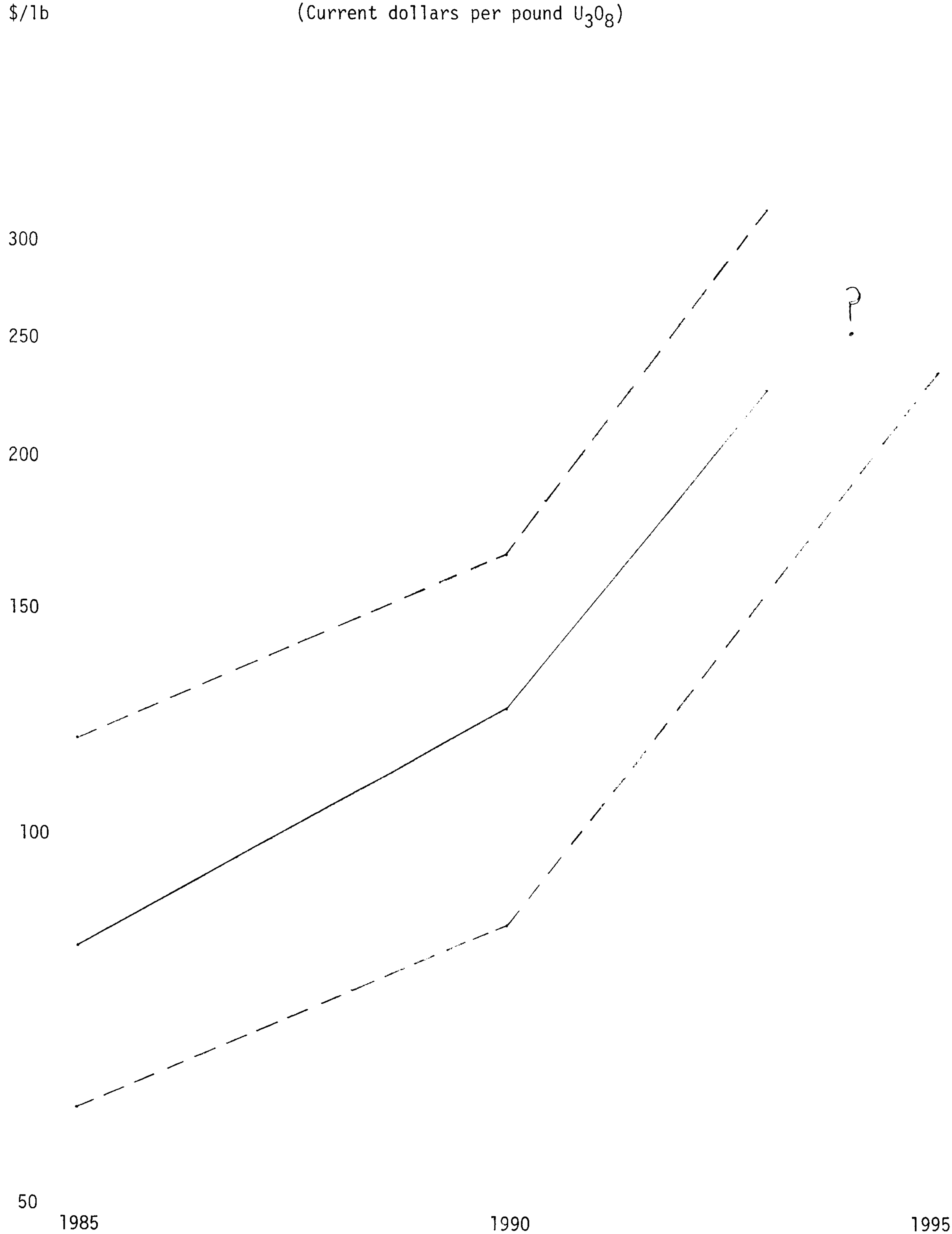


Figure 3.11

PROJECTED 1985-1995 INCREMENTAL URANIUM PRICE
(Current dollars per pound U_3O_8)



c) New methods of exploration could lower the exploration costs of finding uranium

d) Competition from foriegn suppliers or among domestic suppliers could lower prices significantly

e) Nuclear plant delays, plutonium recycle, and additional enrichment capacity could significantly reduce the demand thus depressing the price

In the above figures, the maximum for both average and incremental prices is represented by the upper dashed line. The solid line between the two dashed lines represents a more reasonable projection of price. The incremental price has little meaning through 1985 since lead times prevent an additional nuclear plant being planned for operation in that time frame. Also, the incremental price projection has little meaning once 300 nuclear power plants are operational because the resource base is then totally committed. It is interesting to note that if a utility planned a nuclear plant today for operation in 1995, the utility's plans would be made meaningless if other utilities between 1976 and 1980 committed to a total of 300 nuclear plants for operation prior to 1995 (unless the first utility had already proceeded to developed uranium reserves dedicated to the 1995 nuclear plant).

Table 3.28 lists the projected uranium prices to be used in developing a median and high nuclear fuel cycle cost. All prices after 1995 are estimated by increasing the 1995 price at a 7% inflation rate (since by 1995 all LWR nuclear plants will be assumed to be operational and will be consuming uranium from known deposits in the $15 to $30 cost range subject to yearly inflation).

Table 3.28

MEDIAN AND HIGH PROJECTED URANIUM PRICES
(Current dollars per pound U_3O_8)

Year	Projected Annual Average Price		Projected Incremental Price	
	Median Case	High Case	Median Case	High Case
1976	11.00	11.00	20.00	20.00
1977	12.75	14.00	23.00	24.00
1978	14.75	17.50	26.50	29.00
1979	17.25	22.25	30.50	35.00
1980	20.00	28.00	35.00	42.00
1981	24.00	32.50	41.00	51.50
1982	29.00	38.00	48.50	63.50
1983	34.50	44.00	57.50	78.00
1984	42.00	51.00	67.50	96.00
1985	50.00	59.00	80.00	118.00
1986	53.00	63.00	87.50	127.00
1987	57.00	67.50	96.00	136.00
1988	61.00	72.00	105.00	145.00
1989	64.50	78.00	114.00	155.00
1990	69.00	83.00	125.00	166.00
1991	81.00	102.00	152.50	205.00
1992	94.50	126.00	185.00	255.00
1993	110.00	154.50	225.00	315.00
1994	129.00	189.00	-	-
1995	150.00	232.00	-	-
1996	160.50	248.25	-	-
1997	171.75	265.50	-	-
1998	183.75	284.25	-	-
1999	196.50	304.00	-	-
2000	210.50	325.50	-	-

Enrichment

The gaseous diffusion process of enrichment has been used in the U.S. successfully for over 25 years. To meet the expanding needs of the nation's operating nuclear plants, the federal government has for three years been considering two courses of action. The first option would be to add on an additional enrichment facility at the Portsmouth, Ohio gaseous diffusion plant. The second option would be to allow private enterprise to build gaseous diffusion and centrifuge enrichment plants. Unfortunately the Congress has procrastinated on the Nuclear Fuel Assurance Act of 1975 which was not passed during the 75-76 session. Therefore the earliest point at which private enterprise can proceed on an enrichment facility will be mid to late 1977. Table 3.29 lists the best estimate of enrichment capacity [5], [6].

The projected enrichment capacity appears to be sufficient to supply the maximum enrichment demands of the domestic utilities (Table 3.17) plus supply enrichment for 50 to 100 GWe of foreign LWR nuclear plants. Without the private enrichment, government enrichment capacity will be insufficient to meet high demands at a .3% tails assay level. There is little likelihood that the U.S. Congress would allocate up to 12 billion dollars over a period of ten years to build two full size gaseous diffusion plants.

Table 3.30 lists basic information on the costs of a gaseous diffusion plant and the price of a separative work unit (SWU), [7], [8]. The present 210 Gw(e) of LWR nuclear plants all have enrichment commitments from government enrichment plants now operating. Therefore until the add-on and private gaseous diffusion plants come on line, the pro-

Table 3.29

ENRICHMENT CAPACITY EXPANSION
(Thousands of Separative Work Units)

Year	Base Plants	CIP	CUP	UEA*	Add On	Total
1976	15,100	300	-	-	-	15,400
1977	16,100	1,300	500	-	-	18,000
1978	16,400	2,500	1,500	-	-	20,400
1979	17,200	3,800	2,700	-	-	23,700
1980	17,200	4,900	3,600	-	-	25,700
1981	17,200	5,800	4,500	-	-	27,500
1982	17,200	6,000	4,800	-	-	28,000
1983	17,200	6,000	4,800	-	-	28,000
1984	17,200	6,000	4,800	-	-	28,000
1985	17,200	6,000	4,800	3,000	1,500	32,500
1986	17,200	6,000	4,800	8,750	4,500	41,250
1987	17,200	6,000	4,800	8,750	8,750	45,500
1988	17,200	6,000	4,800	8,750	8,750	45,500
1989	17,200	6,000	4,800	8,750	8,750	45,500
1990	17,200	6,000	4,800	8,750	8,750	45,500

CIP - Cascade Improvement Program-ERDA
CUP - Cascade Uprating Program-ERDA
UEA - Uranium Enrichment Associates-private enrichment

*Announced its dissolution in November 1976.

jected yearly average price and projected incremental price will be the same.

Several additional considerations necessary for projecting enrichment prices are as follows:

a) For the presently installed capacity, the government is increasing its charges to a level more nearly equal to private costs ($79 per SWU is the government's first guess for 1977).

b) It will be assumed that the government finally charges $90 per SWU in 1977 and that the price is escalated every year by 7% until 1985 (including the CIP and CUP) and then half of the price by 7% thereafter.

c) It will be assumed that the final capital expenditure for the add on and private plant will climb to 6 billion dollars each which will include interest during construction, cost escalation, and the original base cost of 3 billion dollars each.

d) It will be assumed that the government will charge the same price for enrichment from its add-on plant as the private enterprise company does for its plant. Otherwise the utility customers would load up the government plant first and leave the privage gaseous diffusion plant without sufficient demand for enrichment during the first few years.

e) The government will use any excess funds collected above to pay for stockpiling enriched uranium to protect against unscheduled, severe gaseous diffusion plant outages.

f) Variable costs in table 3.30 will escalate at 7% per year.

Table 3.31 lists the projected prices for uranium enrichment. One significant event that takes place after 2000 is that the capital charge is dropped from the private enrichment charge due to completion of its capital recovery.

Table 3.30

ECONOMIC INFORMATION FOR GASEOUS DIFFUSION ENRICHMENT
(1975 dollars)

	Public	Private	
Plant Costs	3,000,000,000	3,000,000,000	
Power Costs @ 2.4 ¢/kwh	520,000,000/yr	520,000,000/yr	Var.
Tax Revenues (Local)[a]	-	45,000,000/yr	Fix
Operations Payroll	26,000,000/yr	26,000,000/yr	Var.
Capital Recovery[b]	300,000,000/yr	360,000,000/yr	Fix
Maintenance & General Costs	31,000,000/yr	31,000,000/yr	Var.
Royalties to U.S. Government	-	60,000,000/yr	Fix
Return on Equity (est.)[c]	-	67,500,000/yr	Fix
Federal Income Tax (est.)	-	67,500,000/yr	Fix
	877,000,000/yr	1,177,000,000/yr	
SWU price	$100/kgSWU	$134/kgSWU	

[a] 1½% local and state tax rate

[b] 10% for government and 12% for private enterprise which pays higher money rates and amortizes over a shorter period of time than the government

[c] Equity is 15% of total; return on equity is 15% after taxes.

Table 3.31

PROJECTED ANNUAL AVERAGE AND INCREMENTAL ENRICHMENT COSTS
(Current dollas per Kg SWU)

Year	Present Plants	Add-On & Private	Average	Increment
1976	65.0	-	65.0	65.0
1977	90.0	-	90.0	90.0
1978	96.3	-	96.3	96.3
1979	103.0	-	103.0	103.0
1980	110.3	-	110.3	110.3
1981	118.0	-	118.0	118.0
1982	126.2	-	126.2	126.2
1983	135.1	-	135.1	135.1
1984	144.5	-	144.5	144.5
1985	154.6	266.9	170.3	266.9
1986	160	276.0	197	276.0
1987	165.8	285.7	211	285.7
1988	172.0	296.1	219	296.1
1989	178.6	307.2	228	307.2
1990	185.7	319.2	237	319.2
1991	193.3	331.9	246	331.9
1992	201.4	345.5	256	345.5
1993	210.1	360.1	267	360.1
1994	219.4	375.7	279	375.7
1995	229.3	392.4	291	392.4
1996	240.0	410.3	305	410.3
1997	251.4	429.4	319	429.4
1998	263.6	449.9	335	449.9
1999	276.6	471.8	351	471.8
2000	290.6	495.2	368	495.2

Waste Disposal

After the nuclear fuel has been "burned" in the reactor over a period of 3 to 4 years, one of two alternatives can be followed. The first alternative involves short-term storage of the used fuel assemblies at the nuclear plant, then shipment to a reprocessing facility. There the spent fuel assemblies would be reprocessed into reusable uranium and plutonium and into high level waste. The waste would then be encapsulated and sent to a federal repository for long-term disposal, while the plutonium and uranium would be used as feed material for the front end of the nuclear fuel cycle. The second alternative involves storing the spent fuel assembly for about 11 years, then preparing the assembly for waste disposal and finally long-term storage at a federal repository.

There is little likelihood of the first process being completely implemented before 1985 for the following reasons:

1. The federal government has delayed making its decision on permitting the use of mixed oxide fuel from 1973 to 1977.
2. The government's changing regulations are driving some reprocessors out of business.
3. The capital costs and uncertainties are preventing industry from investing in recycle facilities.

Furthermore, if the cost/benefit analysis of the reprocessing process at the time of federal approval versus the "throwaway cycle" indicates a negative benefit, then use of the throwaway cycle would be continued.

Therefore, the throwaway cycle without reprocessing will be used to provide a reasonable upper cost for that portion of the nuclear fuel cycle.

The primary stages of the throwaway cycle are described in table 3.32. The first federal repository should be ready to accept spent fuel by 1985. In the meantime spent fuel will be maintained at the plant site and at additional storage sites--such as General Electric's Morris, Illinois, site--until the fuel is processed for final storage. To make the analysis straightforward, it is assumed that after 2 years of storage at the plant site all fuel is shipped directly to the federal repository and put into pools at the repository for an additional 9 years.

The primary reason for 11 years of pool storage of a spent fuel assembly is that the decay heat over a period of time will decrease, thus allowing a higher density distribution of waste containers in the federal repository (salt mine).

Although not on exactly the same basis as the reference, the following prices will be used for the nuclear fuel cycle analysis [9]:

Spent Fuel Transportation (special trains)	\$28.6/kgU
Spent Fuel Storage & Disposal	\$82.42/kgU

The above prices are in 1976 dollars and are considered to escalate at 7% per year. The incremental price of these two nuclear fuel cycle components will be assumed to be the same as the average price.

Table 3.32

THROWAWAY CYCLE STEPS

Item	Period (months after end of cycle)
Initial storage at site	0-24
Shipment to intermediate storage	24-26
Intermediate storage	26-132
Preparation for Long-term retrievable storage	133
Long-term retrievable storage	134+

Other Components of the Nuclear Fuel Cycle

Fabrication of nuclear fuel assemblies has been successfully accomplished for several decades. The fabrication is a well-established manufacturing process with a price range of \$90 to \$150 per kilogram Uranium (kgU) [10]. A price of \$120/kgU in 1976 dollars escalated at 7% per year will be used with the incremental price the same as the average price.

Purification/Conversion is another well-established process with an assumed price of \$5/kgU in 1976 dollars escalated at 7% with the incremental price the same as the average price.

Nuclear Fuel Cycle Cost Calculations

Cost calculations are based on a steady state cycle and will ignore the increased cost of the first two cycles and the different leveling schemes that can be used. A nuclear fuel carrying charge rate of 16% will be used along with a 7% rate of inflation and a 9% cost of money/present worth factor. The energy output from the fuel for a 1000 Mw(e) nuclear plant is 6.423 billion kwh. The quantities required per 1000 Mw(e) nuclear plant in the same units as the price are:

U_3O_8 - 410,000 pounds

purification/conversion - 158,000 kg Uranium

enrichment - 82,200 kg Separative Work Units

fabrication, spent fuel shipment, and waste storage/disposal - 24,000 kg Uranium.

Nuclear fuel cycle cost calculations and results are displayed in tables 3.33, 3.34, 3.35, 3.36 and in figures 3.12 and 3.13.

Table 3.33

AVERAGE NUCLEAR FUEL CYCLE COSTS
(current dollars)

1976 Average Cost [11] = $0.0035/kwh

1980

Item	Unit Cost	Base Cost (Million Dollars)	Deflation or Carrying Cost (Million Dollars)	Nuclear Fuel Carrying Charge (Million Dollars)	Total Cost (Million Dollars)	% of Total
U_3O_8	25.00	10.250	1.170	3.043	14.463	32.3
Purification/ Conversion	6.13	.969	.087	.282	1.338	4.3
Enrichment	80.00	6.576	.489	1.883	8.949	37.3
Fabrication	147.01	3.528	.106	.969	4.603	14.9
Spent Fuel Shipment	52.69	1.265	(.342)	-	.923	3.0
Waste Storage/ Disposal	151.53	3.637	(1.023)	-	2.614	8.4
	1980 Average Cost = $.0048/kwh (5.1 mills)				32.890	

1985

Item	Unit Cost	Base Cost (Million Dollars)	Deflation or Carrying Cost (Million Dollars)	Nuclear Fuel Carrying Charge (Million Dollars)	Total Cost (Million Dollars)	% of Total
U_3O_8	42.00	17.220	1.959	5.114	24.293	45.2
Purification/ Conversion	8.59	1.357	.122	.394	1.873	3.5
Enrichment	144.50	11.878	.884	3.402	16.164	30.1
Fabrication	206.18	4.948	.148	1.359	6.455	12.0
Spent Fuel Shipment	73.90	1.774	(.481)	-	1.293	2.4
Waste Storage/ Disposal	212.52	5.100	(1.435)	-	3.665	6.8
					53.743	

1985 Average Cost = $.0084/kwh (8.4 mills)

1990

Item	Unit Cost	Base Cost	Deflation or Carrying Cost	Nuclear Fuel Carrying Charge	Total Cost	% of Total
		Million Dollars				
U_3O_8	64.50	26.445	3.008	7.854	37.307	45.8
Purification/ Conversion	12.05	1.904	.171	.553	2.628	3.2
Enrichment	228.00	18.742	1.395	5.368	25.505	31.3
Fabrication	289.18	6.940	.208	1.906	9.054	11.1
Spent Fuel Shipment	103.65	2.487	(.674)	-	1.813	2.2
Waste Storage/ Disposal	298.07	7.154	(2.013)	-	5.141	6.3
					81.448	

1990 Average Cost = $.0127/kwh (12.7 mills)

1995

Item	Unit Cost	Base Cost	Deflation or Carrying Cost	Nuclear Fuel Carrying Charge	Total Cost	% of Total
		Million Dollars				
U_3O_8	129.00	52.890	6.016	15.708	74.614	56.6
Purification/ Conversion	16.90	2.670	.240	.776	3.686	2.8
Enrichment	279.00	22.934	1.707	6.569	31.210	23.7
Fabrication	405.59	9.734	.292	2.673	12.699	9.6
Spent Fuel Shipment	145.37	3.489	(.945)	-	2.544	1.9
Waste Storage/ Disposal	418.06	10.033	(2.823)	-	7.210	5.5
					131.963	

1995 Average Cost = $.0205/kwh (20.5 mills)

2000

Item	Unit Cost	Base Cost	Deflation or Carrying Cost	Nuclear Fuel Carrying Charge	Total Cost	% of Total
		Million Dollars				
U_3O_8	196.50	80.565	9.163	23.927	13.655	60.3
Purification/ Conversion	23.70	3.745	.337	1.088	4.170	2.2
Enrichment	351.00	28.852	2.147	8.264	39.263	20.8
Fabrication	568.86	13.653	.410	3.749	17.812	9.4
Spent Fuel Shipment	203.89	4.893	(1.326)	-	3.567	1.9
Waste Storage/ Disposal	586.36	14.073	(3.959)	-	10.114	5.4
					188.581	

2000 Average Cost = $.0294/kwh (29.4 mills)

Table 3.34

AVERAGE NUCLEAR FUEL CYCLE COSTS--HIGH URANIUM COST
(current dollars)

1980

Item	Unit Cost	Million Dollars: Base Cost	Deflation or Carrying Cost	Nuclear Fuel Carrying Charge	Total Cost	% of Total
U_3O_8	22.25	9.123	1.038	2.709	12.870	37.9
Purification/ Conversion	6.13	.969	.087	.282	1.338	3.9
Enrichment	103.00	8.467	.630	2.425	11.522	33.9
Fabrication	147.01	3.528	.106	.969	4.603	13.5
Spent Fuel Shipment	52.69	1.265	(.342)	-	.923	2.7
Waste Storage/ Disposal	151.53	3.637	(1.023)	-	2.614	7.7
					33.970	

1980 Average Cost (High Uranium Cost) = $.0053/kwh (5.3 mills)

1985

Item	Unit Cost	Million Dollars: Base Cost	Deflation or Carrying Cost	Nuclear Fuel Carrying Charge	Total Cost	% of Total
U_3O_8	51.00	20.910	2.378	6.209	29.497	50.0
Purification/ Conversion	8.59	1.357	.122	.394	1.873	3.2
Enrichment	144.50	11.878	.884	3.402	16.164	27.4
Fabrication	206.18	4.948	.148	1.359	6.455	11.0
Spent Fuel Shipment	73.90	1.774	(.481)	-	1.293	2.2
Waste Storage/ Disposal	212.52	5.100	(1.435)	-	3.665	6.2
					58.947	

1985 Average Cost (High Uranium Cost) = $.0092/kwh (9.2 mills)

1990

Item	Unit Cost	Million Dollars: Base Cost	Deflation or Carrying Cost	Nuclear Fuel Carrying Charge	Total Cost	% of Total
U_3O_8	78.00	31.980	3.637	9.496	45.113	50.5
Purification/ Conversion	12.05	1.904	.171	.553	2.628	2.9
Enrichment	228.00	18.742	1.395	5.368	25.505	28.6
Fabrication	289.18	6.940	.208	1.906	9.054	10.1
Spent Fuel Shipment	103.65	2.487	(.674)	-	1.813	2.0
Waste Storage/ Disposal	298.07	7.154	(2.013)	-	5.141	5.7
					89.254	

1990 Average Cost (High Uranium Cost) = $.0139/kwh (13.9 mills)

1995

Item	Unit Cost	Million Dollars: Base Cost	Deflation or Carrying Cost	Nuclear Fuel Carrying Charge	Total Cost	% of Total
U_3O_8	189.00	77.490	8.814	23.009	109.313	65.6
Purification/ Conversion	16.90	2.670	.240	.776	3.686	2.2
Enrichment	279.00	22.934	1.707	6.569	31.210	18.7
Fabrication	405.59	9.734	.292	2.673	12.699	7.6
Spent Fuel Shipment	145.37	3.489	(.945)	-	2.544	1.5
Waste Storage/ Disposal	418.06	10.033	(2.823)	-	7.210	4.3
					166.662	

1995 Average Cost (High Uranium Cost) = $.0259/kwh (25.9 mills)

2000

Item	Unit Cost	Million Dollars: Base Cost	Deflation or Carrying Cost	Nuclear Fuel Carrying Charge	Total Cost	% of Total
U_3O_8	304.00	124.640	14.176	37.008	175.824	70.1
Purification/ Conversion	23.70	3.745	.337	1.088	4.170	1.7
Enrichment	351.00	28.852	2.147	8.264	39.263	15.7
Fabrication	568.86	13.653	.410	3.749	17.812	7.1
Spent Fuel Shipment	203.89	4.893	(1.326)	-	3.567	1.4
Waste Storage/ Disposal	586.36	14.073	(3.959)	-	10.114	4.0
					250.750	

2000 Average Cost (High Uranium Cost) = $.0390/kwh (39.0 mills)

Table 3.35

INCREMENTAL NUCLEAR FUEL CYCLE COSTS
(current dollars)

1980

Item	Unit Cost	Base Cost (Million Dollars)	Deflation or Carrying Cost (Million Dollars)	Nuclear Fuel Carrying Charge (Million Dollars)	Total Cost (Million Dollars)	% of Total
U_3O_8	30.50	12.505	1.422	3.713	17.630	45.6
Purification/ Conversion	6.13	.969	.087	.282	1.338	3.5
Enrichment	103.00	8.467	.630	2.425	11.522	29.9
Fabrication	147.01	3.528	.106	.969	4.603	11.9
Spent Fuel Shipment	52.69	1.265	(.342)	-	.923	2.4
Waste Storage/ Disposal	151.53	3.637	(1.023)	-	2.614	6.8
					38.660	

1980 Incremental Cost = $.0060/kwh (6.0 mills)

1985

Item	Unit Cost	Base Cost (Million Dollars)	Deflation or Carrying Cost (Million Dollars)	Nuclear Fuel Carrying Charge (Million Dollars)	Total Cost (Million Dollars)	% of Total
U_3O_8	67.50	27.675	3.148	8.217	39.040	57.0
Purification/ Conversion	8.59	1.357	.122	.394	1.873	2.7
Enrichment	144.50	11.878	.884	3.402	16.164	23.6
Fabrication	206.18	4.948	.148	1.359	6.455	9.4
Spent Fuel Shipment	73.90	1.774	(.481)	-	1.293	1.9
Waste Storage/ Disposal	212.52	5.100	(1.435)	-	3.665	5.4
					68.490	

1985 Incremental Cost = $.0107/kwh (10.7 mills)

Table 3.35 Continued

1990

Item	Unit Cost	Base Cost (Million Dollars)	Deflation or Carrying Cost (Million Dollars)	Nuclear Fuel Carrying Charge (Million Dollars)	Total Cost (Million Dollars)	% of Total
U_3O_8	114.00	46.740	5.316	13.878	65.934	55.4
Purification/ Conversion	12.05	1.904	.171	.553	2.628	2.2
Enrichment	307.20	25.252	1.879	7.233	34.364	28.9
Fabrication	289.18	6.940	.208	1.906	9.054	7.6
Spent Fuel Shipment	103.65	2.487	(.674)	-	1.813	1.5
Waste Storage/ Disposal	298.07	7.154	(2.013)	-	5.141	4.3
					118.934	

1990 Incremental Costs = $.0185/kwh (18.5 mills)

1995

Item	Unit Cost	Base Cost (Million Dollars)	Deflation or Carrying Cost (Million Dollars)	Nuclear Fuel Carrying Charge (Million Dollars)	Total Cost (Million Dollars)	% of Total
U_3O_8	272.00	111.520	12.684	33.113	157.317	69.8
Purification/ Conversion	16.90	2.670	.240	.776	3.686	1.6
Enrichment	375.70	30.883	2.298	8.846	42.027	18.6
Fabrication	405.59	9.734	.292	2.673	12.699	5.6
Spent Fuel Shipment	145.37	3.489	(.945)	-	2.544	1.1
Waste Storage/ Disposal	418.06	10.033	(2.823)	-	7.210	3.2
					225.483	

1995 Incremental Costs (estimate) - $.0351/kwh (35.1 mills)

Table 3.36

INCREMENTAL NUCLEAR FUEL CYCLE COSTS--HIGH URANIUM COST
(current dollars)

1980

Item	Unit Cost	Million Dollars: Base Cost	Deflation or Carrying Cost	Nuclear Fuel Carrying Charge	Total Cost	% of Total
U_3O_8	35.00	14.350	1.632	4.261	20.243	49.0
Purification/ Conversion	6.13	.969	.087	.282	1.338	3.2
Enrichment	103.00	8.467	.630	2.425	11.552	28.0
Fabrication	147.01	3.528	.106	.969	4.603	11.2
Spent Fuel Shipment	52.69	1.265	(.342)	-	.923	2.2
Waste Storage/ Disposal	151.53	3.637	(1.023)	-	2.614	6.3
					41.273	

1980 Incremental Cost (High Uranium Cost) = $.0064/kwh (6.4 mills)

1985

Item	Unit Cost	Million Dollars: Base Cost	Deflation or Carrying Cost	Nuclear Fuel Carrying Charge	Total Cost	% of Total
U_3O_8	96.00	39.360	4.477	11.687	55.524	65.3
Purification/ Conversion	8.59	1.357	.122	.394	1.873	2.2
Enrichment	144.50	11.878	.884	3.402	16.164	19.0
Fabrication	206.18	4.948	.148	1.359	6.455	7.6
Spent Fuel Shipment	73.90	1.774	(.481)	-	1.293	1.5
Waste Storage/ Disposal	212.52	5.100	(1.435)	-	3.665	4.3
					84.974	

1985 Incremental Cost (High Uranium Cost) = $.0132/kwh (13.2 mills)

Table 3.36 Continued

1990

Item	Unit Cost	Million Dollars: Base Cost	Deflation or Carrying Cost	Nuclear Fuel Carrying Charge	Total Cost	% of Total
U_3O_8	155.00	63.550	7.228	18.869	89.647	62.8
Purification/ Conversion	12.05	1.904	.171	.553	2.628	1.8
Enrichment	307.20	25.252	1.879	7.233	34.364	24.1
Fabrication	289.18	6.940	.208	1.906	9.054	6.3
Spent Fuel Shipment	103.65	2.487	(.674)	-	1.813	1.3
Waste Storage/ Disposal	298.07	7.154	(2.013)	-	5.141	3.6
					142.647	

1990 Incremental Cost (High Uranium Cost) = $.0222/kwh (22.2 mills)

1995

Item	Unit Cost	Million Dollars: Base Cost	Deflation or Carrying Cost	Nuclear Fuel Carrying Charge	Total Cost	% of Total
U_3O_8	385.00	157.850	17.954	46.869	222.673	76.6
Purification/ Conversion	16.90	2.670	.240	.776	3.686	1.2
Enrichment	375.70	30.883	2.298	8.846	42.027	14.5
Fabrication	405.59	9.734	.292	2.673	12.699	4.4
Spent Fuel Shipment	145.37	3.489	(.945)	-	2.544	.9
Waste Storage/ Disposal	418.06	10.033	(2.823)	-	7.210	2.5
					290.839	

1995 Incremental Cost (High Uranium Cost) (estimate) = $.0453/kwh (45.3 mills)

Figure 3.12

NUCLEAR FUEL CYCLE COSTS 1976-1985

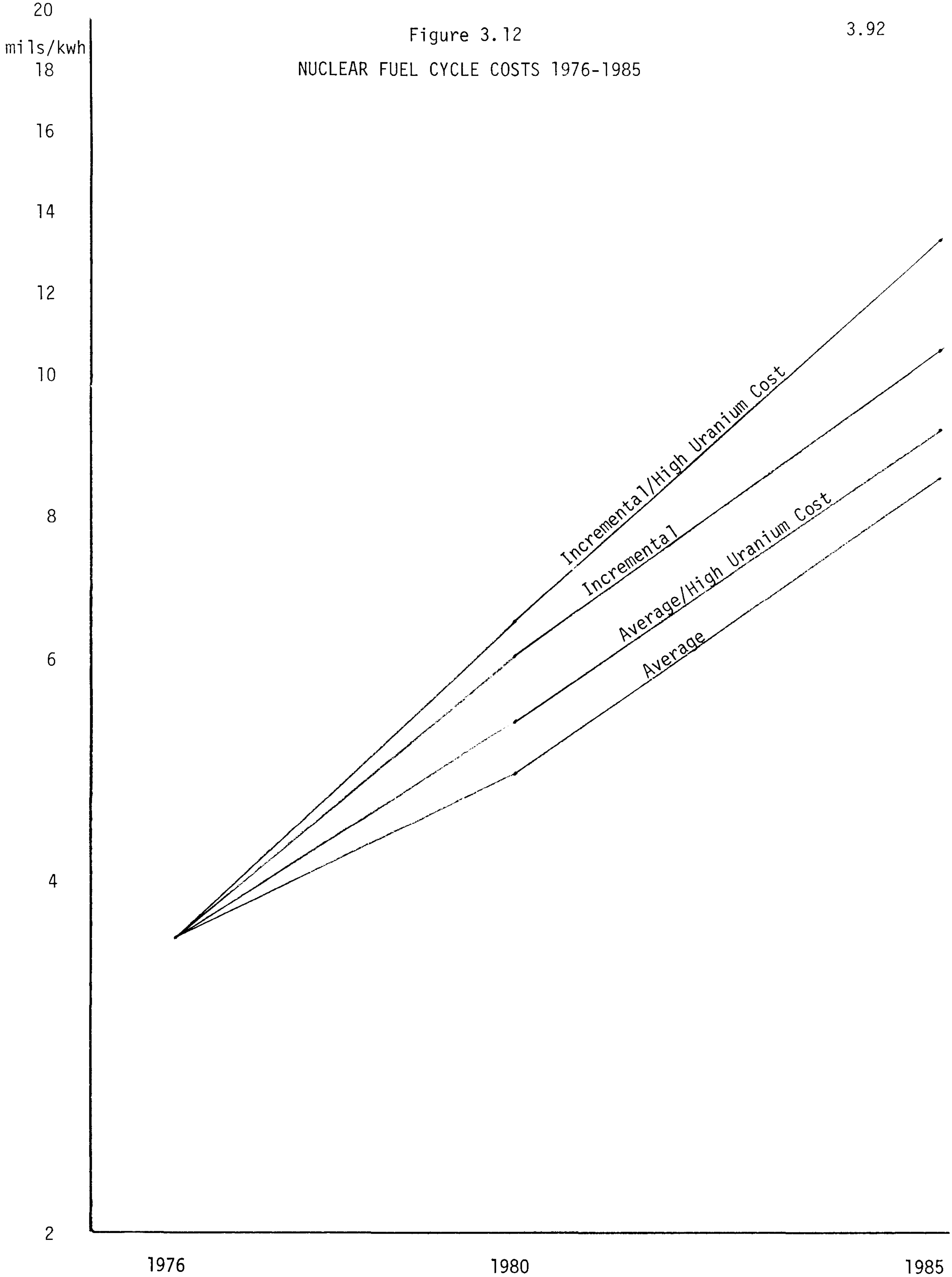
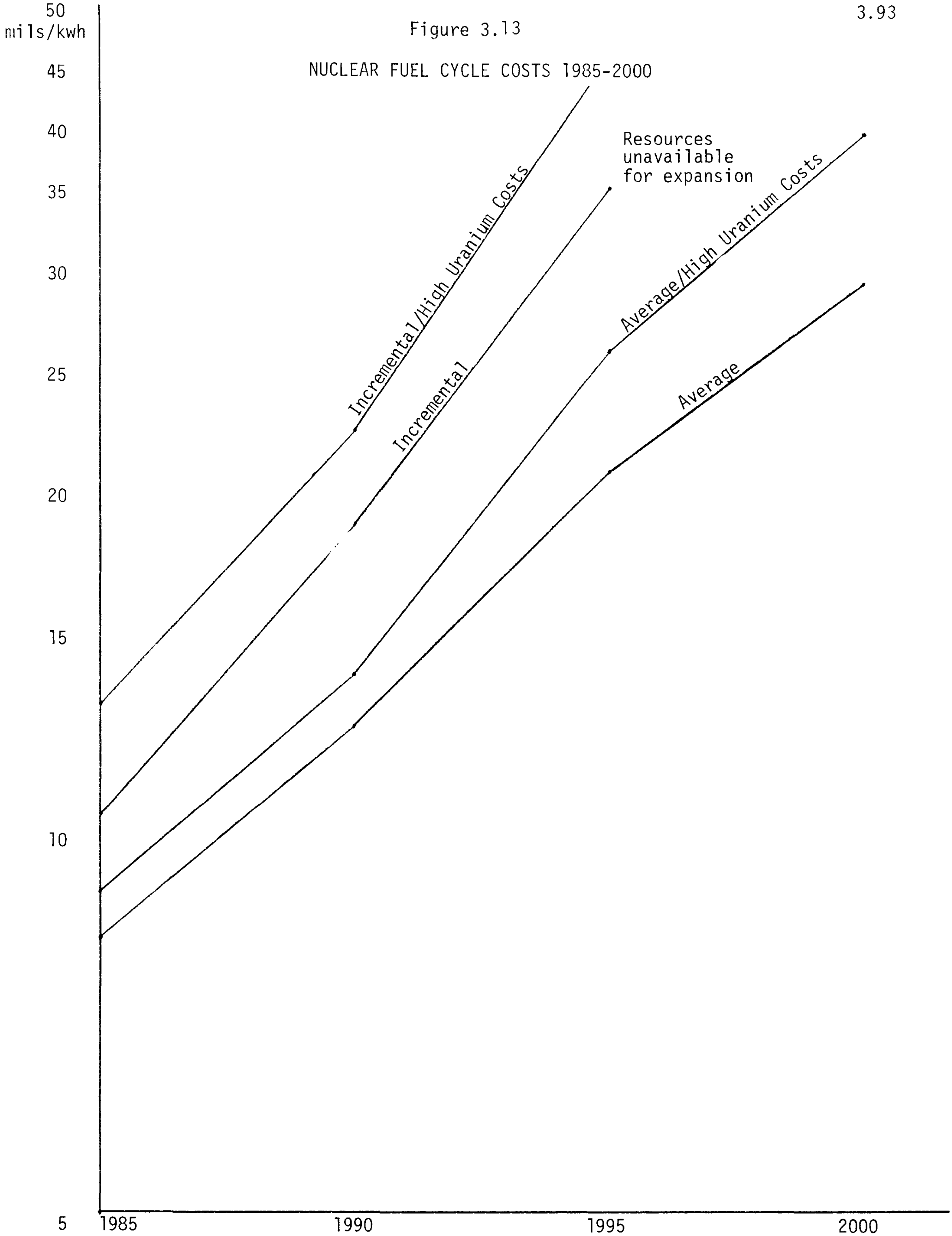


Figure 3.13

NUCLEAR FUEL CYCLE COSTS 1985-2000



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3.4 Oil and Gas

Interstate sales of natural gas are under the regulation of the Federal Power Commission which controls the price. However intrastate sales are unregulated and recent sales in the state have been contracted at prices considerably above the interstate rate. Natural gas resources have been depleting rapidly and since the early 1970s production has been falling. Contracts for delivery of natural gas in the past have been signed at prices well below today's cost, and deliveries on these contracts will absorb much of the state's identified proven reserve potential. The declining production trends and continuing delivery on interstate contracts leads us to believe that the real average price of natural gas to electric utilities in Texas will continue to rise in the future.

By 1985, the use of natural gas as a boiler fuel will be curtailed by 25% over its 1974 or 1975 consumption level by order of the Texas Railroad Commission. The construction of new gas-fired plants will be disallowed, resulting in a gradual phasing-out of gas consumption by electric utilities. Ultimately, natural gas will be used by electric utilities only as a start up fuel for coal-burning plants.

In our analysis, the base case assumes that the price of natural gas will not be regulated within the state of Texas, however, interstate sales are assumed to be regulated by the FPC as they have been in the past.

The availability of oil is an area that is highly uncertain. Currently, the U.S. imports about 40% of its annual oil requirements. In the absence of major breakthroughs in transportation technologies, oil will remain the primary source of energy in the transportation sector. If existing regulatory policies continue in the future, i.e., oil prices remain regulated, the high cost of exploratory drilling will not motivate increased exploration. This could result in a substantial reduction in oil availability, or a major increase in oil importation at prices controlled by the oil cartel.

If oil prices are deregulated they can be expected to catch up to the cost of imported oil. However, in either case, the price of oil can be expected to rise to a level close to that set by the OPEC.

The Texas Governor's Energy Advisory Council provided the expected prices of these fuels for the different cases that were analyzed. Table 3.37 presents the gas and oil prices used in the study. In this study it was assumed these prices reflect the availability of these fuels except where availability constraints are additionally imposed.

TABLE 3.37

FUTURE OIL AND GAS PRICES IN TEXAS[+]

Fuel	Cases	Price - 1985
Oil	All cases	\$13/bbl crude (1975\$)
Gas	Deregulated Gas prices	\$3.40/mcf (1975\$)
Gas	Regulated Gas price	\$1.42/mcf (1976\$)
Gas	Gas Consumption to Zero	\$1.31/mcf (1976\$)

[+]Source: Texas Governor's Energy Advisory Council.

3.5 COAL TRANSPORTATION

It is estimated that by 2000 between 50 to 80 million tons of western coal may be needed in Texas to meet expected electricity demands. All of this coal will come primarily from the states of Wyoming, Montana, Colorado, and New Mexico over an average distance of 1500 miles. The question is whether there is enough capability in our transportation system to carry this load. It is more reasonable for one to consider this question on a national level mainly because of its nature and geographical scope, but the problem can be narrowed down to the state of Texas by considering the transportation modes available to the state. Because of the tremendous volume of coal to be moved, only railroads and slurry pipeline shall be considered here.

RAILROAD

Historically, the railroad and coal industries have been heavily interdependent. Railroads have hauled more coal than any other mode of transportation and coal has been the largest single commodity moved by rails. The data available for the year 1974 show this interdependency. In 1974, the nation produced about 600 million tons of coal of which railroads helped transport about 390 million tons and generated $1.8 billion in revenue. The situation is expected to stay the same with the present technology available.

One of the major methods of transporting coal on railroads is the unit train. It is worth noting that between 1971 and 1975, there was a 64% increase in coal tonnage moved by unit trains, while the total tonnage moved by rail increased only 14.8%. It is also expected that growth rates of unit trains will be accelerating. Unit trains came into being about 15 years ago, and were originally developed to make railroads capable of competing with coal slurry pipelines, low cost nuclear energy, and mine-mouth power plants. A unit train for normal coal movement can be defined as a string of one-hundred 100-ton cars which remain coupled together throughout the coal movement; it operates on loop tracks at the end of which it is loaded or unloaded without stopping.

The two factors most often identified as possibly constraining future movement of coal by rail are hopper car availability and capital. The following table shows the response of the car building industry to the recent historical demand for new cars.

TABLE 3.38

OPEN TOP HOPPER STATISTICS

	TOTAL CARS AS OF DEC. 31	CARS ORDERED	CARS DELIVERED	ON ORDER DEC. 31
1972	383,242	5,387	7,059	2,725
1973	365,330	13,254	3,157	10,621
1974	356,626	27,086	7,323	28,242
1975	363,186	13,175	21,748	18,949

The table shows that the backlog of car orders has reduced since 1974. If the utilities indicate a commitment towards using rail transportation for moving coal, then more capital must be raised for upgrading the existing tracks and installing new ones.

Rail service from the previously identified coal supplying western states is mostly provided by Burlington Northern (BN) and its subsidiaries, the Fort Worth and Denver (FWD) and the Colorado and Southern (CS) railroads. There are other railroads which may be involved in coal transportation to Texas such as the Atchison, Topeka and Santa Fe (ATSF), Southern Pacific (SP), Missouri Pacific (MP), Chicago, Rock Island and Pacific (CRIP) and the Missouri-Kansas-Texas (MKT). BN, ATSF, SP, and MP are in sound financial situations and should be able to maintain and increase their capacity to meet future demand.

COAL SLURRY PIPELINE

Another mode of transportation which may be available to the state of Texas is the coal slurry pipeline method of moving coal over long distances. The principal idea, briefly, is that coal is mined and ground to an average size of 0.05 inch. It is then mixed with water or some other suitable fluid in an equal proportion (50-50) and pumped through a pipeline system. At the destination point, the coal is dewatered and then burned in the boiler.

Not enough experience has been accumulated about this mode of transportation, but what there is, is favorable. The first pipeline was put into operation in 1957 by Consolidation Coal Company; carried 1.3 million tons per year of coal over a distance of 108 miles from Cadiz, Ohio to near Cleveland. It went out of operation because of the competition it received from the introduction of unit trains. The second pipeline, operated by Black Mesa Pipeline Company, moves 5 million tons of coal per year from northeast Arizona to a Mohave power plant in southern Nevada. It went into operation in 1970.

Three elements favor the economics of coal slurry pipelines:

1. Since they are capital intensive a large portion of the future total cost is immune to future inflation. The following table gives the cost distribution for capital, labor and fuel.

TABLE 3.39

COST DISTRIBUTION IN COAL SLURRY PIPELINE

Initial Investment	70%
Labor	6%
Fuel and Supply	24%
TOTAL	100%

2. Reliability is good. Based on limited experience, the two pipeline systems have shown a reliability factor of 98% or more. This factor can be approximated as that of the power system supplying the pipeline.
3. Environmental impact is minimal, except for the water usage. The pipeline produces almost negligible amounts of air and noise pollution.

There are also some drawbacks:

1. The right of eminent domain is lacking. Legislation to ease this restriction is necessary if large scale use of this technology is to be possible.
2. Water usage problems continue to be the major drawback of the pipeline idea. Since most of the major coal-

producing states are located in the semiarid Northern Plains region, the quality and quantity of water remaining in the ground once a pipeline system starts operation in that area is not fully known.

3. Operation of the pipeline is highly inflexible. The economics depend on high usage factors because of the high fixed costs.

Both of these transportation modes may be able to meet the future demand for coal movement, but because of the uncertainties existing in the future demand and supply of energy, railroads seem to have a near term advantage over the pipeline industry because it is an established industry and it has a more proven technology.

3.6 Water Requirements and Resources

3.6.1 Water Requirements for Extraction and Processing of Energy

Water demands for production of electric power must take into account those required for the extraction and processing of the fuels. These requirements can be summarized as follows (1): (see table 3.40)

Table 3.40
WATER REQUIREMENTS FOR ENERGY PRODUCTION AND CONVERSION

Fuel Process	Unit Water Requirements Gallons Per MWh
Secondary Oil Recovery	600
Natural Gas Processing	42
Lignite Stripping	4.3
Uranium	0.43
Coal Gasification	400-1600
Coal Liquefaction	320

For comparison, the upstream fuel cycle water consumption requirements for the respective fuel types are listed by another source (2), as follows: (see table 3.41)

Table 3.41
UPSTREAM FUEL CYCLE WATER REQUIREMENTS FOR
ALTERNATIVE ELECTRIC POWER GENERATION ENERGY SOURCES

		Water Consumption (Acre-feet/1000 MW-Year)		
Fuel	Extraction	Transportation	Processing	Total
Nuclear	188	0	95	283
Coal	4055	6	0	4061
Oil	0	0	1590	1590
Gas	0	0	0	0

Hoffman (3) listed the water requirements for a theoretical plant using 25,000 tons of lignite per day in a recent paper on "Water for Lignite Development in Texas." From these data, the unit requirements for alternative energy conversion strategies are shown in Table 3.42.

Table 3.42
COMPARATIVE WATER REQUIREMENTS FOR
ALTERNATIVE LIGNITE ENERGY CONVERSION STRATEGIES

	(Acre-feet of Water per 1000 tons of Coal)			
	Water Intake		Water Consumption	
Process	Min.	Max.	Min.	Max.
Coal-fired Power Plant	2.55 -	164.7	1.45 -	2.77
Coal Gasification	0.72 -	165.0	0.57 -	2.10
Coal Liquefaction	0.70 -	164.8	0.44 -	2.08
In Situ Gasification	1.32 -	82.4	0.72 -	1.27
Pipeline Slurry	0.64 -	0.85	0.09 -	0.85

The consumption of water per unit of heat output for these alternative energy conversion strategies has been shown in Table 3.43.

Table 3.43
WATER REQUIREMENTS FOR
ALTERNATIVE LIGNITE ENERGY CONVERSION STRATEGIES

Process	Output Heat (Million Btu per ton Fuel)	Water Consumption (Gallons per million Btu)
Power Plant	4.8	98-188
Gasification	9.2-12.0	15-74
Liquefaction	5.2-9.2	16-130
In Situ Gasification	2.8	84-148
Pipeline Slurry	14.4	0.2-19

3.6.2 COOLING WATER REQUIREMENTS

A. General

Approximately 95% of the power demand in the state of Texas is generated by natural-gas-fired power plants. The other 5% is generated by hydroelectric, coal or lignite, gas turbine, internal combustion, and combined cycle-power generators. The small gas turbine, internal combustion and combined cycle systems are used to meet peak period power demands during the summer months of July and August. It is generally predicted that steam-electric plants will continue to be dominant in the next several decades.

Steam-electric power plants operate on the thermodynamic process known as the Rankine cycle. Process water is converted into steam, which drives the turbine-generator to produce electricity. If the steam were released to the atmosphere, about 40-50% of the steam's energy would be lost. Hence, the steam is condensed and then reheated and vaporized. It is this condensing process that requires large quantities of cooling water.

Cooling water is circulated in the condenser and is raised in temperature by 15 to 20°F. The amount of water needed depends on this temperature differential, the type of plant, its thermal efficiency, and the type of cooling system used. Nuclear power plants generally have greater demands for cooling water than fossil fuel plants because of their lower thermal efficiency of 30-33%, as compared to 37-40%.

There are two major categories of cooling systems, namely, once-through and recirculating. Once-through systems pump water from a large natural body of water through the condensers, and return this heated water to the same source or another large body of water. It uses either fresh water or saline water. Recirculating systems include wet cooling towers, dry cooling towers, cooling ponds, spray ponds, and combined modes.

Once-through systems require a very high intake of water as compared to recirculating systems, but the latter (except dry towers) have a much greater consumption as a result of the evaporation process. Once-through systems are more economical, but they have to be near a large body of surface fresh water or along the coast, where large quantities of sea water can be constantly drawn. Wet towers and ponds are widely used due to their low intake and less thermal discharge into surface waters; but the water evaporated by these systems is actually consumed, because it is not available to downstream locations as in the once-through case. Dry cooling towers conserve the cooling water in closed systems, but they involve very high capital costs due to large heat transfer areas, as well as high power requirements for operation. The use of spray ponds is currently very limited in Texas, and few data have been collected about the system.

It is important to note the distinction between a cooling pond and a multipurpose lake. A cooling pond can be defined as a body of water which was constructed solely for the purpose of power plant cooling and would not otherwise exist. All evaporation from a cooling pond is considered the evaporative consumption of the plant. A multipurpose lake is generally a natural body of water which is used for purposes other than cooling, such as water supply, recreation, fishing, etc. In this case, not all the evaporative loss can be allocated to the power plant.

Evaporation from a cooling pond depends heavily on local climate, such as rainfall, humidity, and wind conditions. Natural evaporation rate in West Texas is sufficiently high that even well-designed ponds will consume more water than wet cooling towers because of the low humidity levels. The opposite is true for East Texas, where higher humidity levels prevail. The preferential use between ponds and towers by regions for the state of Texas can be illustrated as in Figure 3.14 (3).

The typical water consumption requirements, power requirements, and comparative capital costs by alternative cooling systems for a theoretical plant at Houston, Texas, are tabulated in Table 3.44 (3). Important to note from these data are the following: (a) considerably higher water use for nuclear plants relative to fossil fuel plants; (b) significant difference in water consumption between ponds designed for 1 acre of surface area per megawatt and ponds designed for two acre/Mw; and (c) the exceedingly high capital cost and power requirements for dry cooling towers.

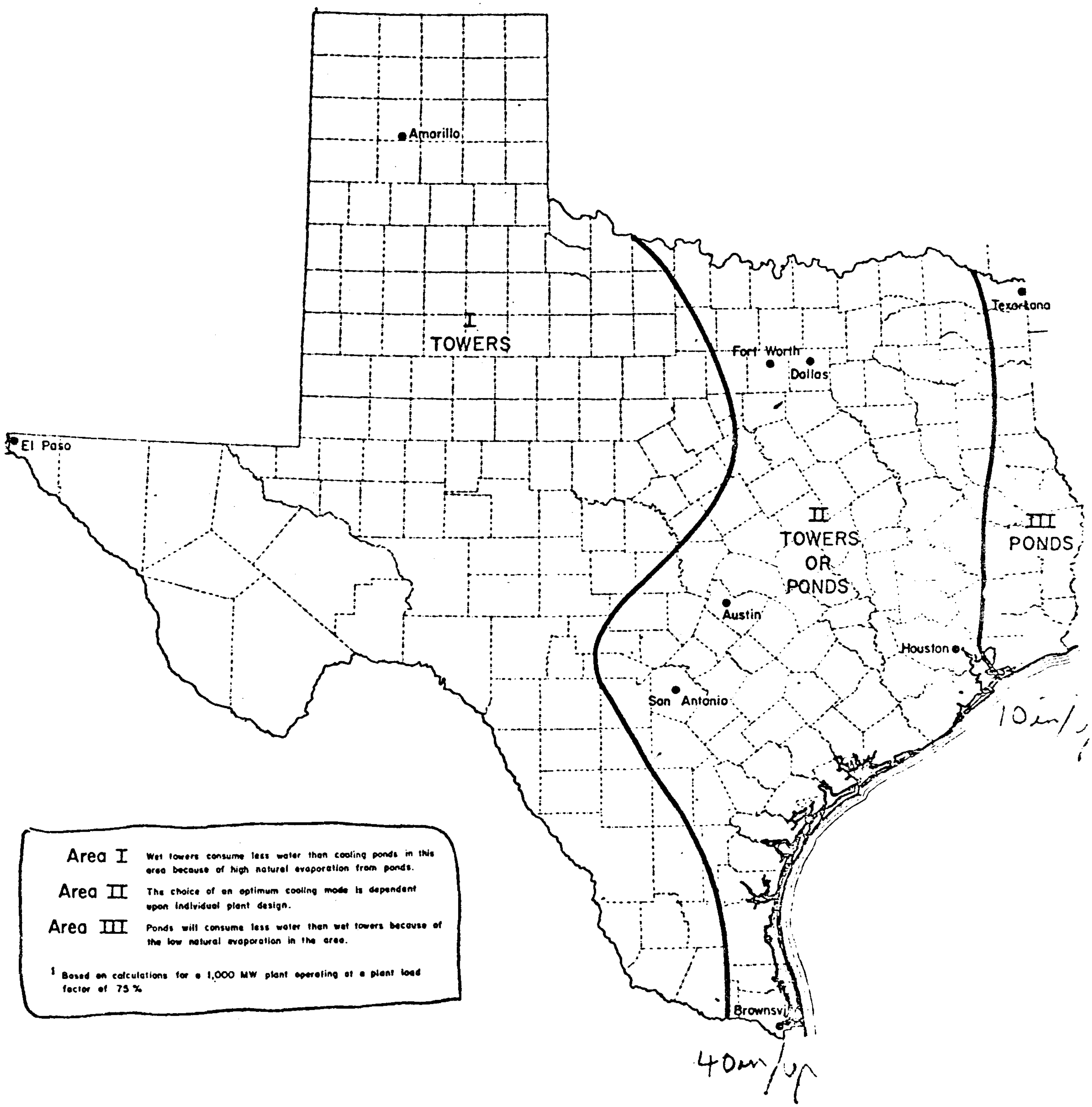
It is observed that the water consumption rates of once-through systems and wet towers are relatively similar. Wet towers, relative to once-through systems, should proportionately consume more water than indicated (ratio of about 2 to 1), which was not explained in the source literature.

B. Water Requirement Calculations

Of the total fuel heat that is inputed into a plant, a portion of it is lost up the stack or radiated from the boiler surfaces. Radiation from boiler surfaces is about 15% for a fossil fuel plant, and 5% for a nuclear plant. A total of 3413 Btu are theoretically needed to generate one kilowatt-hour

FIGURE 3.14

EVALUATION OF WATER CONSUMPTION[1] FOR WET TOWERS VS. COOLING PONDS



(kwh) of electricity at 100% efficiency. Therefore, the heat dissipated to the cooling water (abbreviated HCW), in Btu/kwhr can be calculated by:

$$HCW = (0.85)\ (hr) - 3413 \qquad \text{(Fossil plants)}$$

$$HCW = (0.95)\ (hr) - 3413 \qquad \text{(Nuclear plants)}$$

where HR = heat rate = total heat input in Btu for the production of one kwh of electricity. Hence,

$$HR = \frac{3413 \text{ Btu/kwh}}{\text{Plant Overall Efficiency}}$$

(1) Intake Requirements

The intake of water for once-through systems can be calculated by the following condensed formula:

$$\text{Intake} = \frac{HCW}{(8.34)\ (dT)}$$

where Intake = Gallons per kWH

HCW = Heat to Cooling Water, in Btu/kwh

dT = Temperature rise of cooling water, in °F

(2) Evaporative Consumption Requirements

Whenever a cooling device (such as wet towers, ponds) is used for cooling the recirculating cooling water, not all the waste heat is dissipated by evaporation. Heat transfer from cooling water to the atmosphere is also accomplished by conduction, convection, and radiation. The proportion of heat dissipated by evaporation, which is a function of local climatic conditions, can be labeled the "Evaporative Factor" (EF). EF factors for ten climatic regions of Texas have been studied (4), and they can be summarized in Table 3.45.

TABLE 3.44

TYPICAL WATER CONSUMPTION, COST, AND POWER REQUIREMENTS
FOR
ALTERNATIVE COOLING SYSTEMS

(For a Theoretical Plant, 1000 M at 75% Load Factor at Houston, Texas)

Cooling System	Cooling Water Consumption (gallons)					(Capital Cost) Cost Ratios Assuming "Once-through Fresh" =1.0 = $4000/M in 1970	Power Requirement	
	Nuclear	Oil	Gas	Hard Coal	Texas Lignite		% Drop in Plant Overall Efficiency	% of Total Capacity to Operate Cool
	(Overall Plant Efficiency)							
	32%	40%	40%	39%	38%			
1. Dry Towers	0	0	0	0	0	4.0 - 5.0	12% +	3.0-8.0%
2. Wet Towers	0.57	0.35	0.35	0.37	0.37	1.5 - 1.8	slight	3%
3. Once-through Fresh	0.40	0.25	0.25	0.26	0.26	1.0	0	<1%
4. Once-through Saline	0.40	0.25	0.25	0.26	0.26	1.1	0	<1%
5. Ponds, 1.0 acre/M	0.46	0.32	0.32	0.33	0.33	1.3- 1.5	0	<1%
6. Ponds, 2.0 acre/M	0.59	0.43	0.43	0.44	0.44	1.3- 1.6	0	<1%

TABLE 3.45

EVAPORATIVE HEAT DISSIPATION FACTORS FOR DIFFERENT REGIONS OF TEXAS

	Climatic Region	Yearly Average Evaporative Factor Once-through Cooling	Wet Cooling Towers
1.	High Plains	0.52	0.80
2.	Low Rolling Plains	0.51	0.80
3.	North Central	0.53	0.79
4.	East Texas	0.49	0.80
5.	Trans Pecos	0.53	0.82
6.	Edwards Plateau	0.50	0.80
7.	South Central	0.59	0.81
8.	Upper Coast	0.55	0.81
9.	Southern	0.58	0.82
10.	Lower Valley	0.59	0.83

Using these evaporative factors, the evaporative water consumption can be calculated with the relationship:

$$\text{Evaporative Water Consumption} = \frac{(\text{HCW})(\text{EF})}{(8760)}$$

where Evaporative Water Consumption = Gallons per kwh

HCW = Heat to Cooling Water, in Btu/kwh

EF = Evaporative Factor, in decimals

8760 = Btu/gal = Latent Heat of Evaporation

A paper (5) was published on the evaporative water loss being a function of wet-bulb temperatures and relative humidity of the ambient air. A curve was presented, relating these two factors with evaporation rate in lb/1000

Btu, as shown in Figure 3.15.

Typical figures of water consumption by various types of cooling towers were summarized by a study (2), and can be tabulated in Table 3.46.

TABLE 3.46

CONSUMPTIVE WATER REQUIREMENTS FOR ALTERNATIVE COOLING TOWER STRATEGIES

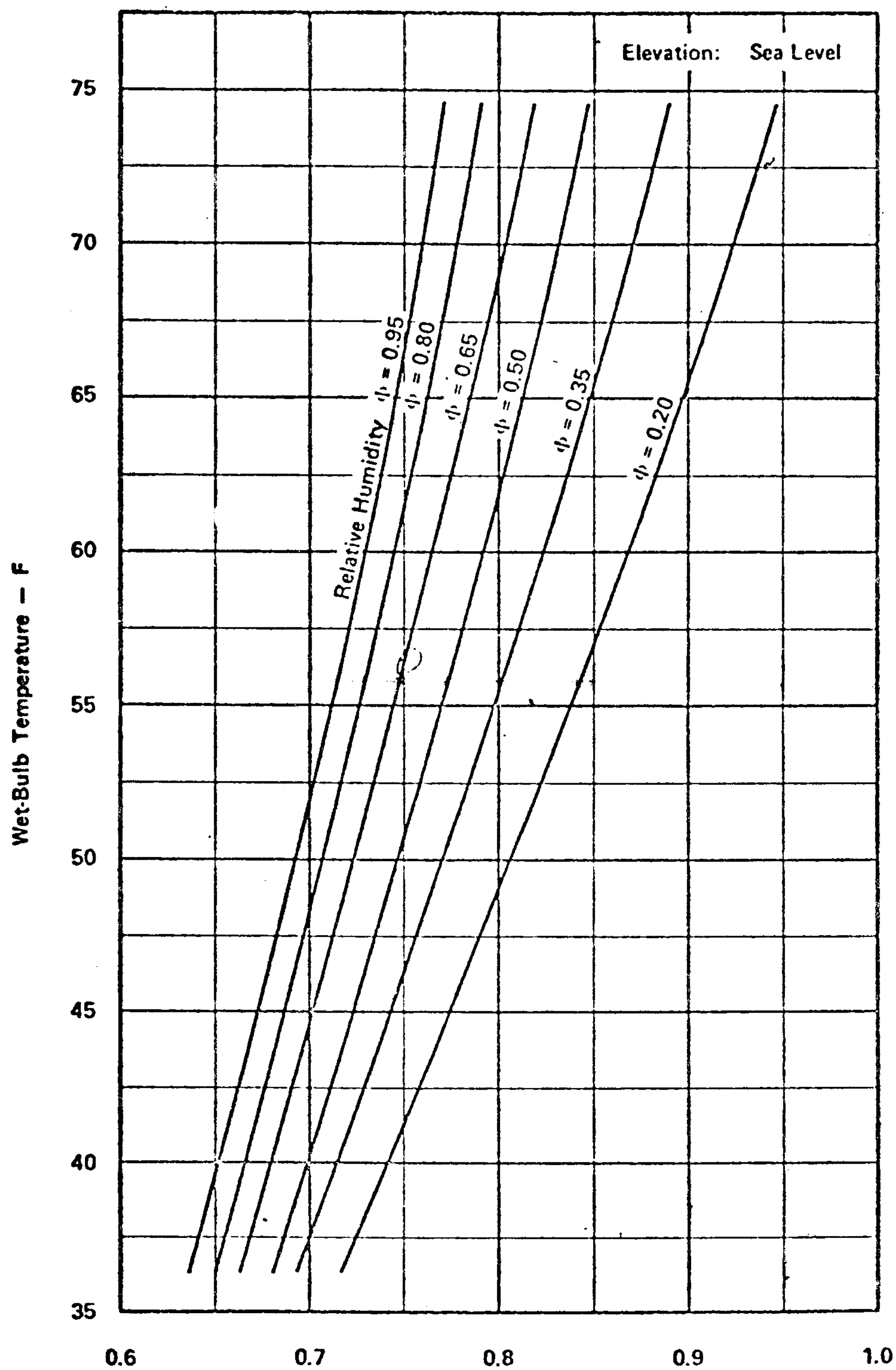
Type of Tower	Water Consumption (acre-ft/1000 Mw(e)-year) Coal-Fired Plant	Nuclear Plant
Dry Tower	160	200
Wet-Dry Tower	5,000	7,000
Wet Tower	11,700	15,700
Cooling Ponds	11,800	15,800

C. Other Water Losses

Make-up water is needed in a power plant not only to replenish the evaporative consumption as described above, but also to account for blowdown and drift losses. Blowdown is employed to prevent concentration build-up in the cooling water due to evaporation; a small amount of water has to be drawn constantly from the storage basin. This blowdown rate depends on the make-up water quality. Generally, 5 to 11 concentrations are used. (A "5 concentration" means that the blowdown has dissolved solids levels five times the water supply). The volume of blowdown can be expressed by the relation:

$$\text{Blowdown Rate} = \frac{\text{Evaporation Rate}}{\text{Cycles of Conc.} - 1}$$

The blowdown, however, can be considered a nonconsumptive use, if the water is returned to its source or used in some beneficial manner.



$$\text{Evaporation Rate} \simeq \frac{\text{lb/hr}}{1000\ \text{Btu/hr}} - \frac{1\ \text{lb}\ H_2O}{1{,}000\ \text{Btu}}$$

FIGURE 3.15

COOLING LAKES

Drift losses in a wet tower include water in the form of small droplets which may be carried out of the tower by the high-velocity air flow. This can be maintained below 0.008% of the recirculatory water flow with a drift eliminator. A more effective drift eliminator can reduce this to 0.002% in a mechanical draft tower and 0.0005% in a natural draft tower.

D. Mechanical Draft vs. Natural Draft Towers

The air-to-water ratio in a mechanical draft tower is nearly always constant, but this is not the case for natural draft towers. For the latter, air flow rate in the winter is 140% of that in the summer, because of the greater temperature and density differentials. A natural draft tower designed for summer conditions will have higher air-to-water ratios, which will increase the air-sensible heat transfer and thereby reduce the water evaporative loss. It was found that the annual evaporative loss in a natural draft tower would be about 3% less than in a mechanical draft tower (5).

3.6.3 OTHER WATER REQUIREMENTS

A typical new power plant, say, of 1500 Mw capacity, would bring in 400 to 2000 new persons (employees and their families), and up to 6000 persons, including the business and services attracted to the area. The intake of fresh water for this population would be about 300-900 acre-ft/year, with a mean of 600 acre-ft/year. The consumption would be about 150-450 acre/ft/year, with a mean of 300 acre-ft/year.

For on site water consumption other than cooling, a former study (2) had listed the different uses for various types of plants, as in Table 3.47.

TABLE 3.47

ON-SITE WATER CONSUMPTION REQUIREMENTS FOR OTHER THAN COOLING

Process	Water Consumption (acre-ft/1000 Mw(e)-year) Nuclear	Coal	Oil	Gas
Boiler Feed	50-60	10-55	10-55	10-55
Sanitary	10-20	10-20	10-20	10-20
Particulate Removal	0	0-1500	0	0
SO_2 Scrubbing	0	1040-1660	0	0
TOTAL	60-80	1060-3235	20-75	20-75
Approximate percentage of plant's total use	0.4-.05	13.2-21.2	0.1-0.2	0.1-0.2

TABLE 3.48

SUMMARY OF GROUNDWATER AVAILABILITY BY RIVER BASIN

Basin	(Revised) Sustainable Annual Yield (Acre-feet)
1. Canadian	91,000
2. Red	348,000
3. Sulphur	5,700
4. Cypress	15,000
5. Sabine	98,000
6. Neches	311,000
7. Neches-Trinity	14,000
8. Trinity	238,000
9. Trinity-San Jacinto	36,000
10. San Jacinto	295,000
11. San Jacinto-Brazos	82,000
12. Brazos	476,000
13. Brazos-Colorado	68,000
14. Colorado	562,000
15. Colorado-Lavaca	8,000
16. Lavaca	86,000
17. Lavaca-Guadalupe	48,000
18. Guadalupe	144,000
19. San Antonio	322,000
20. San Antonio-Nueces	30,000
21. Nueces	208,000
22. Nueces-Rio Grande	115,000
23. Rio Grande	695,000
TOTAL	4,295,700

3.6.4 Water Availability in Texas

A. Groundwater

Data are available from a Texas Water Development Board (TWDB) publication (6) on the revised groundwater resources of the state. In this new evaluation, figures shown in the Texas Water Plan (1968) were revised. It showed that a total of 4,295,700 acre-feet of groundwater is annually available as sustainable annual yield. In this analysis, only groundwater with less than 300 mg/l total dissolved solids was included. It also assumed that all proper methods for obtaining groundwater would be used in all locations. Tables 3.48 and 3.49, respectively, summarize the groundwater resources by basin and by aquifer. Figures 3.16 and 3.17 show the locations of the major and minor aquifers respectively.

"Sustainable Annual Yield" is the amount of groundwater which can be safely withdrawn perennially throughout the extent of the aquifer without reducing the amount of water in storage. This, in effect, equals the effective recharge.

B. Water Supply and Demand by Basin

In the latest published Texas Water Plan (1968) by the TWDB, the projected water supply and demand for the year 2020 was described (7). It included ground and surface water supply, the demand in and out of basins, as well as any export or import of water for the basins under the Texas Water System. It also showed that several basins would have surplus water. These data are summarized as in Table 3.50.

A revised edition of the Texas Water Plan is currently in progress in the

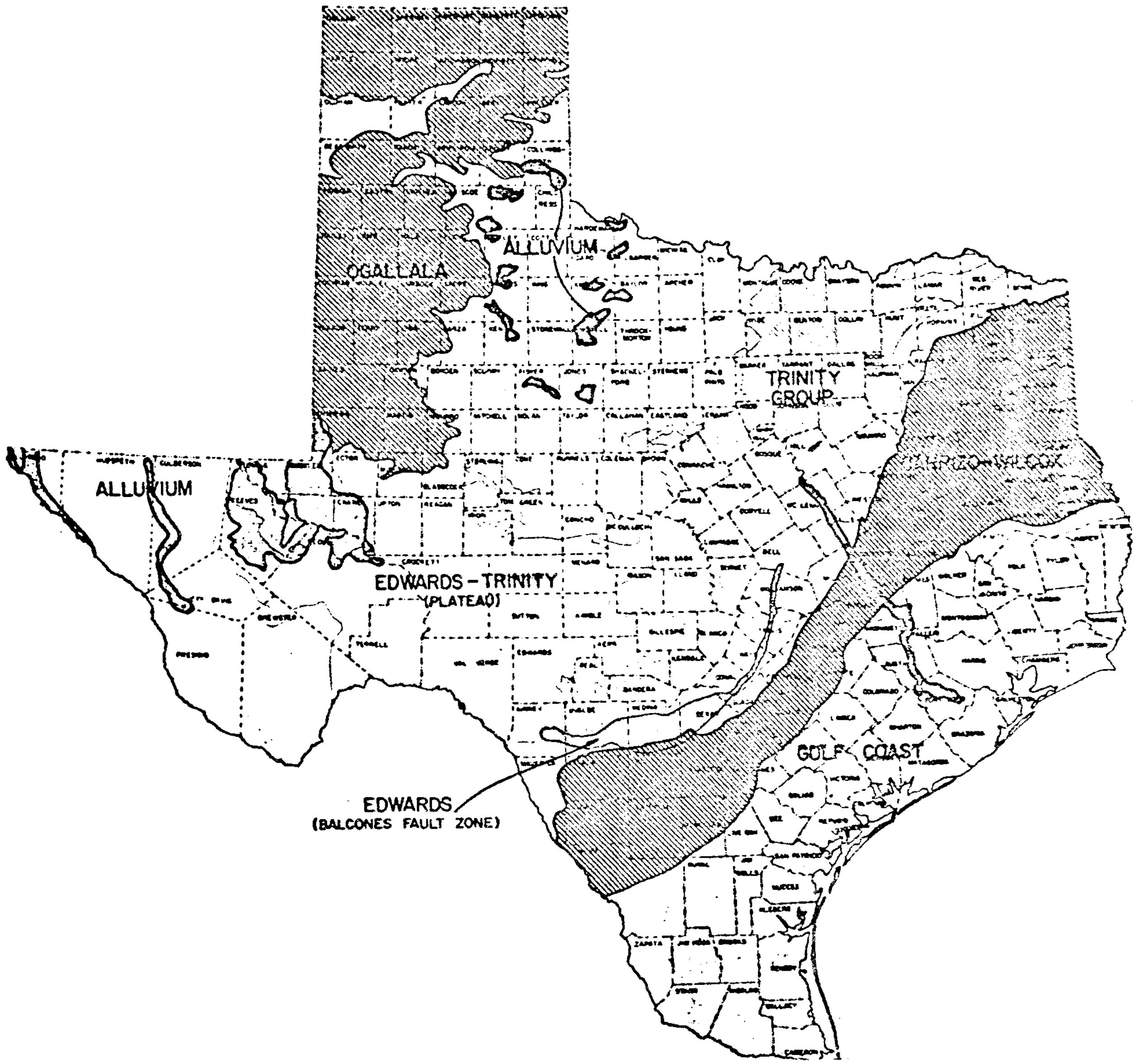


FIGURE 3.16

MAJOR AQUIFERS

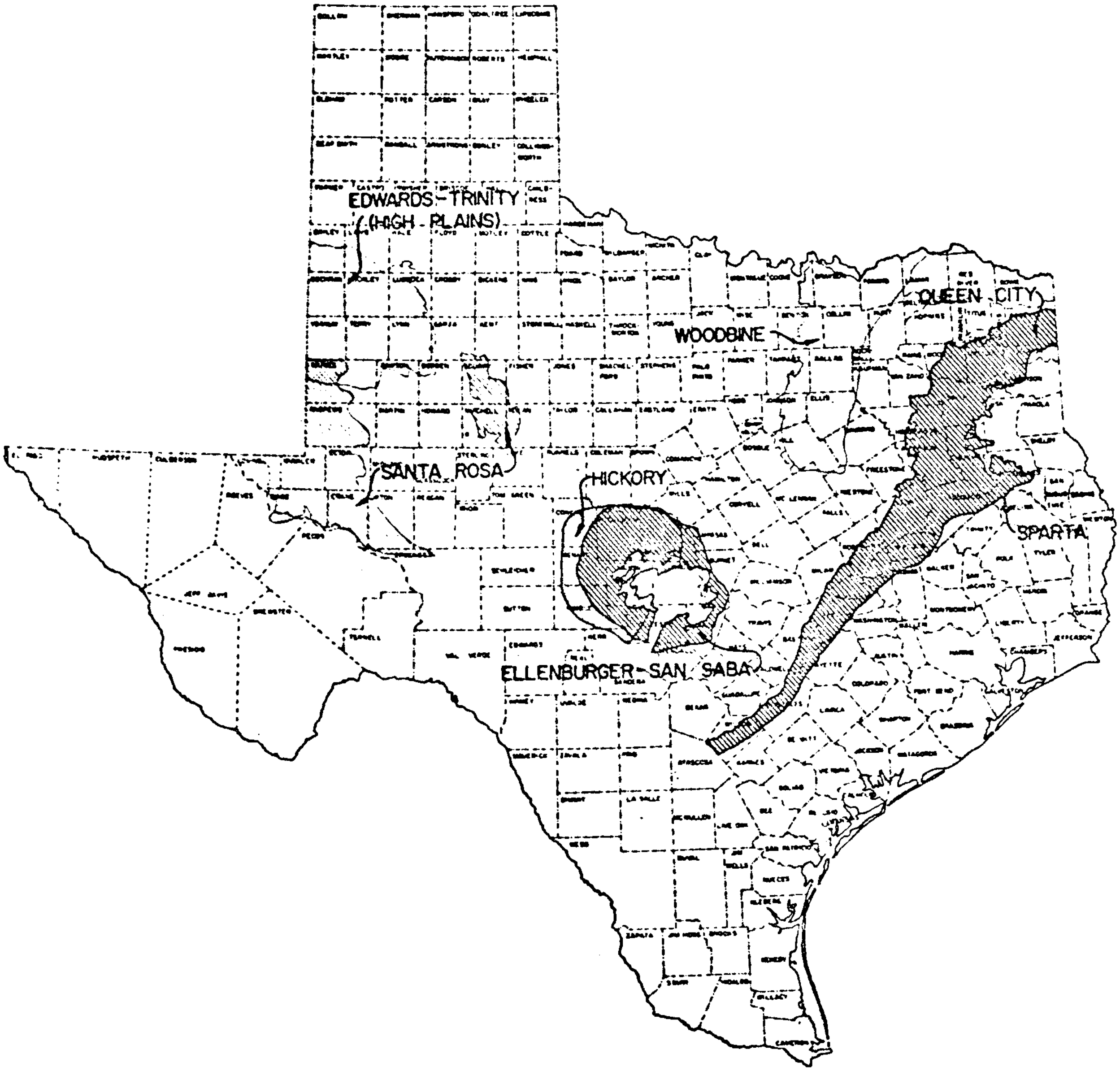


FIGURE 3.17

MINOR AQUIFERS

TABLE 3.49

SUMMARY OF GROUNDWATER AVAILABILITY BY AQUIFER

Aquifer	(Revised) Sustainable Annual Yield (Acre-feet)
MAJOR	
Ogallala	298,000
Carrizo-Wilcox	602,400
Edwards (Balcones Fault Zone)	399,700
Trinity Group	96,200
Alluvium and Bolson Deposits	398,200
Gulf Coast	1,143,400
Edwards-Trinity (Plateau)	784,100
MINOR	
Woodbine	25,100
Queen City	51,500
Sparta	152,000
Santa Rosa	23,500
Hickory Sandstone	52,600
Ellenburger-San Saba	29,400
Marble Falls Limestone	26,400
Blaine Gypsum	142,600
Igneous Rocks	10,700
Marathon Limestone	18,300
Bone Spring & Victoria Peak Limestones	17,000
Captain Limestone	5,000
Rustler	14,000
Nacatoch Sand	900
Blossom Sand	1,300
Other undifferentiated	3,400
Edwards-Trinity (High Plains)	Included with Ogallala aquifer
Purgatoire-Dakota	Included with Ogallala aquifer
TOTAL	4,295,700

TABLE 3.50

SUMMARY OF WATER SUPPLY AND DEMAND IN YEAR 2020 BY RIVER BASINS

(Thousands of Acre-feet/year)

iver Basin	In Basin Supply Ground Water	In Basin Supply Surface Water	Total	In-Basin Demand	Demand Out-of-Basin Demand	Export Under TWS	(-) Import Under TWS	(+) Surplus
anadian	1288.1	103.1	1391.2	1339.4	51.8			
ed	363.7	1262.8	1626.5	901.2	6.1	647.0		72.2
ulfur	0	1426.9	1426.9	170.2	97.8	1105.0		53.9
ypress	6.0	897.9	903.9	165.3		641.0		97.6
abine	141.3	2091.8	2233.1	989.7	199.0	870.0		174.4
eches	296.8	2937.6	3234.4	1022.9	1183.4	1027.9		
eches-Trinity	0.2	1306.7	1306.9	1306.9				
rinity	183.7	3830.4	4014.1	2041.0	1211.5	761.6		
rinity-San Jacinto	50.0	172.2	222.2	222.2				
an Jacinto	492.4	1558.2	2050.6	2646.5	282.8		878.7	
an Jacinto-Brazos	79.9	969.1	1049.0	1049.0				
razos	749.9	1595.3	2345.2	1504.9	829.9			10.4
razos-Colorado	124.9	254.4	379.3	379.3				
olorado	319.4	1236.5	1555.9	980.8	626.2	85.0		
olorado-Lavaca	75.0	251.0	326.0	326.0				
avaca	199.0	361.3	560.3	390.0	170.3			
avaca-Guadalupe	50.7	304.5	355.2	355.2				
uadalupe	104.3	458.4	562.7	250.5	51.6	256.1		
an Antonio	276.5	377.7	654.2	516.0	126.7	216.5	205.0	
an Antonio-Nueces	25.1	45.6	70.7	317.3			246.6	
ueces	167.6	222.5	390.1	447.6	169.9		227.4	
ueces-Rio Grande	51.8	973.1	1024.9	3000.5			1975.6	
o Grande	290.1	2008.4	2298.5	1249.7	848.8	200.0		
TOTAL	- 5336.4	24,645.4	(=)29,981.8	(+)21,572.1	(+)5860.3	(+)5725.1	(-)3618.3	(+)408.5

TWDB. When the next edition is published, these data will have to be checked against the new projections.

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7. The Texas Water Plan, Texas Water Development Board, (November, 1968).

3.7 Capital Costs of Nuclear, Coal, and Oil Plants

Eight in-state and two out-of-state utilities were surveyed to determine future capital costs of electric generating facilities. To a large extent the information provided was based on actual projects under construction with the individual utilities' best estimate of future inflation and cost of money.

Several points should be discussed prior to analyzing the data:

1. Historically the utilities in Texas have constructed power plants at lower capital costs than the surrounding regions. The out-of-state capital cost will be considered as the upper limit for the average in-state plant capital cost.
2. The cost of plants as reported by in-state utilities in some instances varies widely. Without a detailed side-by-side comparison of cost estimates, justification for state variations is difficult. However, within the state the east, northeast, north, and Panhandle sections appear to have similar costs while the southeast, central, south, and west sections are grouped fairly close together. The differences could be caused by varying labor rates, availability of materials, and costs of land. The cost of equipment appears to be priced on a national basis with transportation a fairly insignificant part; therefore, equipment price probably has little to do with the capital cost difference in-state. This analysis will accept that there are cost differences across the state and will use an average between the north and south.
3. Because the City of Austin Electric Department (COA), San Antonio City Public Service (CPS), and Omaha Public Power District (OPPD) are publicly operated electric utilities, they are able to finance

their projects at a lower rate and pay less taxes on the equipment, materials, and plant construction. The capital costs of publicly operated utilities should be adjusted upward by 10-15% when compared with a private utility. In addition the COA does not include interest during construction in its capital cost but takes it out of operating income; therefore, COA's cost should be adjusted upward by 30-40% when compared with private utilities.

4. The cost of a lignite plant will be slightly higher than the cost of a coal plant. The main increases in cost are related to fuel-handling equipment. Owing to the lower heat content of lignite, anywhere from 50 to 100% more material must be processed than for subbituminous coal (10,000 Btu/lb). Higher capacity pulverizers, larger boilers, and larger pollution control equipment would be required. However, most of the costly equipment would remain the same: turbines, generators, boiler feedpumps, cooling towers or ponds, condensors, controls, and control room. There would be an insignificant increase in the need for structural material such as concrete and steel and very little additional labor required to mount the larger equipment. All in all, a cost difference of less than 5% would be expected between a comparable coal and lignite plant. Therefore, coal and lignite plant costs will be treated as the same. This position does not preclude a sizable difference in plant capital costs if differing environmental impacts are considered, such as low sulfur subbituminous coal without the need for scrubbers.

5. For the expected case, capital costs for nuclear, coal, and oil escalate at the same rate--7%--since the plants basically have the

same materials, are constructed by labor in the same region, run on equipment from national manufacturers who use the same national indices (such as SIC 1013) to cover the inflation in their costs, and have IDC at the same rates. However, each plant is subjected to meeting additional regulatory requirements. In the case of nuclear plants, seismic-resistant fire protection (sprinkler systems) may be required along with a second shutdown system to cover Anticipated Transients Without Scram (ATWS). Future requirements could add up to $75/kw of additional costs by 1985. For coal and lignite plants, the primary concern is that more stringent environmental requirements along with poor results from present scrubber designs could add up to $100/kw of additional cost by 1985. The resulting effective inflation rates for modified nuclear and coal/lignite plants would be 8.0 and 8.9% respectively. Because of the law enacted by Congress requiring future oil plants to actually be coal plants, only a base 7% escalation case is considered for oil plants. Any fossil fuel plants completed after 1979 will be treated as coal plants that can burn other fuels.

3.7.1 Nuclear Plant Capital Costs

Figure 3.18 displays the data points for nuclear plant capital costs. The City of Austin (COA) estimate for its share of the South Texas Nuclear Project should be adjusted from $450/kw up to a level of about $600/kw to reflect IDC, sales taxes, and the like. The Omaha Public Power District (OPPD) estimate should be adjusted upward to about $850/kw to put the estimate on a private-utility basis.

Figure 3. 18

PROJECTED CAPITAL COSTS - NUCLEAR POWER PLANTS
(Current dollars)

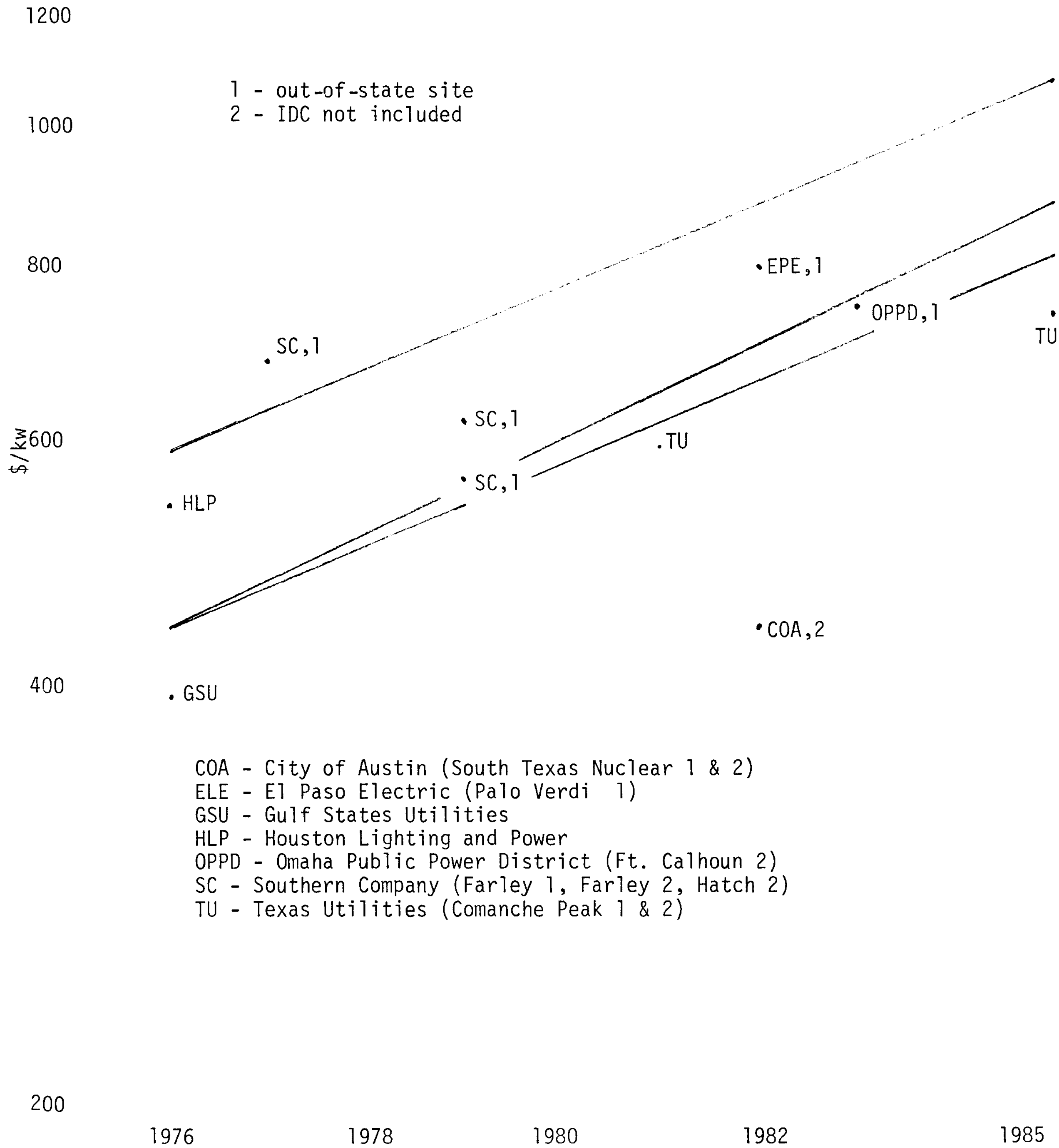

Table 3.51

NUCLEAR PLANT CAPITAL COST
(Dollars per kilowatt)

	1976	1980	1985
Average capital cost	450	590	825
High averate capital cost	450	610	900
Worst-case average capital cost	600	790	1100

With those adjustments made, Texas Utilities and Gulf States Utilities indicate the low range of costs; Houston Lighting and Power, City of Austin, and El Paso Electric indicate the high range of costs; Southern Company and Omaha Public Power District indicate the level of out-of-state costs in the surrounding regions.

Deflating individual costs at 7% back ot 1976 dollars, the average in-state utility cost is $446.6/kw with a standard deviation of $92/kw, therefore, a $450/kw average cost will be used. Inflating the 1976 average at 7% results in an expected average capital cost of $825/kw in 1985. For the high average case, an additional $75/kw (per point #6) results in a nuclear plant capital cost of $900/kw in 1985. From figures 3.7-1 a worst-case average capital cost line is indicated going from $600 to $1100/kw. These data are summarized in table 3.51.

3.7.2 Coal/Lignite Plant Capital Costs: With Scrubbers

Figure 3.19 displays the capital cost data points for coal/lignite plants with scrubbers. The City Public Service (CPS) estimate should be adjusted from $485/kw up to $534/kw to put the estimate on a private-utility basis. The Omaha Public Power District (OPPD) estimate should be adjusted upward to about $815/kw to put the estimate on an equal basis.

With those adjustments made, Texas Utilities, Gulf States Utilities, and Southwestern Public Service indicate the low range of costs; Houston Lighting and Power, El Paso Electric, and City Public Service indicate the high range of cost; Omaha Public Power District indicates a somewhat higher out-of-state cost.

Figure 3.19

PROJECTED CAPITAL COSTS - COAL PLANTS
(OR LIGNITE) WITH SCRUBBERS
(Current dollars)

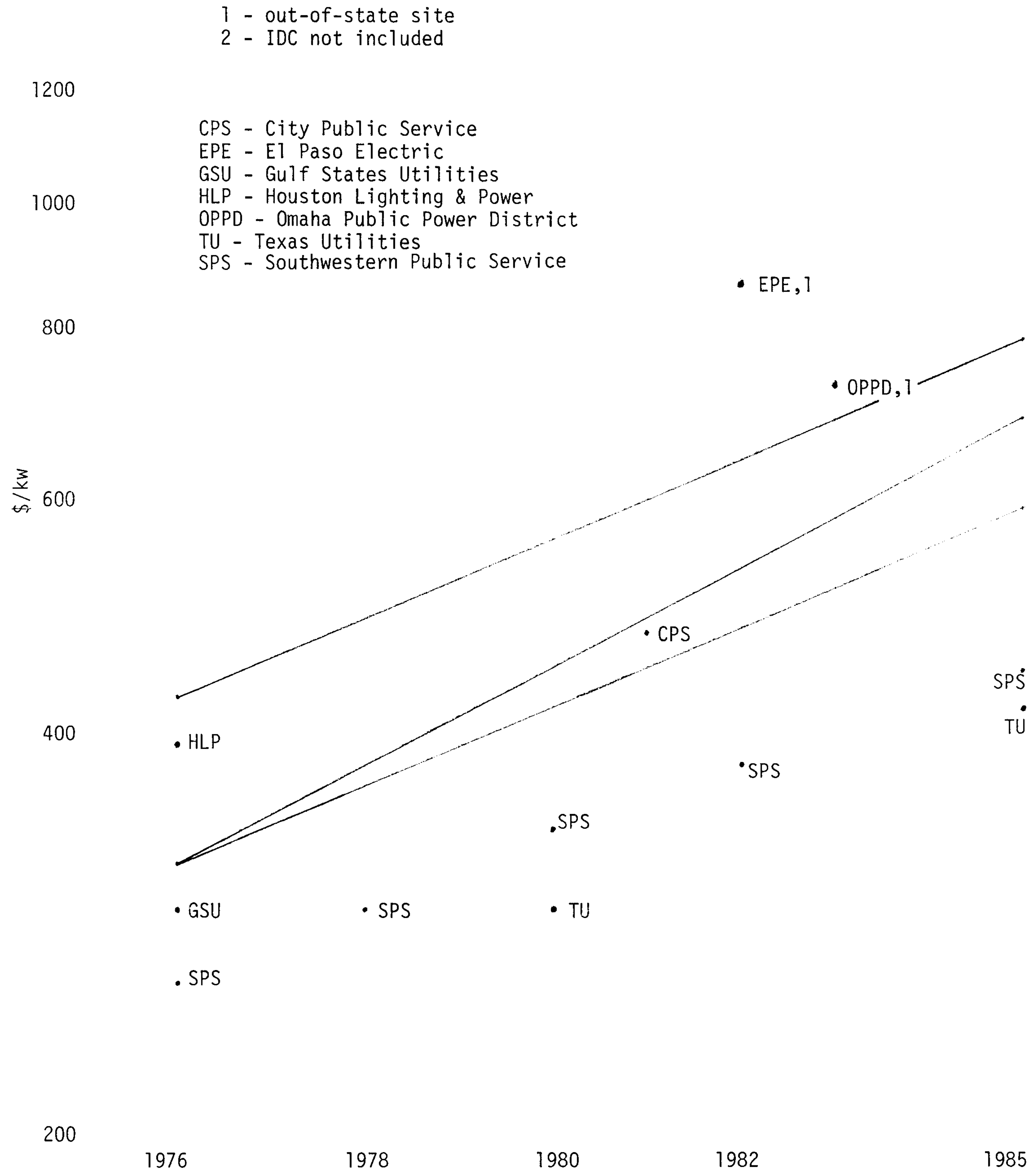

Table 3.52

COAL/LIGNITE PLANT CAPITAL COSTS - WITH SCRUBBERS
(Dollars per kilowatt)

	1976	1980	1985
Average capital cost	325	425	600
High average capital cost	325	455	700
Worst-case average capital cost	435	570	800

Deflating individual costs at 7% back to 1976 dollars, the average in-state utility cost is $315/kw with a standard deviation of $73/kw; therefore, a $325/kw average cost will be used. Inflating the 1976 average at 7% results in an expected average capital cost of $600/kw in 1985. For the high average case, an additional $100/kw (per point #6) results in a coal/lignite plant capital cost of $700/kw in 1985. From figure 3.19 a worst-case average capital cost line is indicated going from $435 to $800/kw. These data are summarized in table 3.52.

3.7.3 Coal/Lignite Plant Capital Cost: Without Scrubbers

Figure 3.20 displays the capital cost data points for coal/lignite plants without scrubbers. The City of Austin average plant capital cost for Fayette 1 and 2 is $397/kw in 1980. Adjusting this estimate downward for including the coal pile, coal cars, and switchyard, and then adjusting that result upward for IDC, taxes, and so forth, gives a cost of $460/kw. The City Public Service estimate should be adjusted to a level of $380/kw to put the estimate on a private-utility basis. The Omaha Public Power District estimate should be raised to $705/kw to put it on an equal basis. (Note: One reason for the wide fluctuations in cost for the same utility is that the cost of shared facilities such as control room, cooling ponds, and so forth, are lumped in on the cost of the first unit of a two-unit plant.)

With those adjustments made, Southwestern Electric Power indicates the low range of costs; Houston Lighting and Power, City of Austin, and City Public Service indicate the high range costs; Southern Company and Omaha Public Power District indicate slightly higher out-of-state costs.

Figure 3. 20

PROJECTED CAPITAL COSTS - COAL PLANTS
(OR LIGNITE) WITHOUT SCUBBERS
(Current dollars)

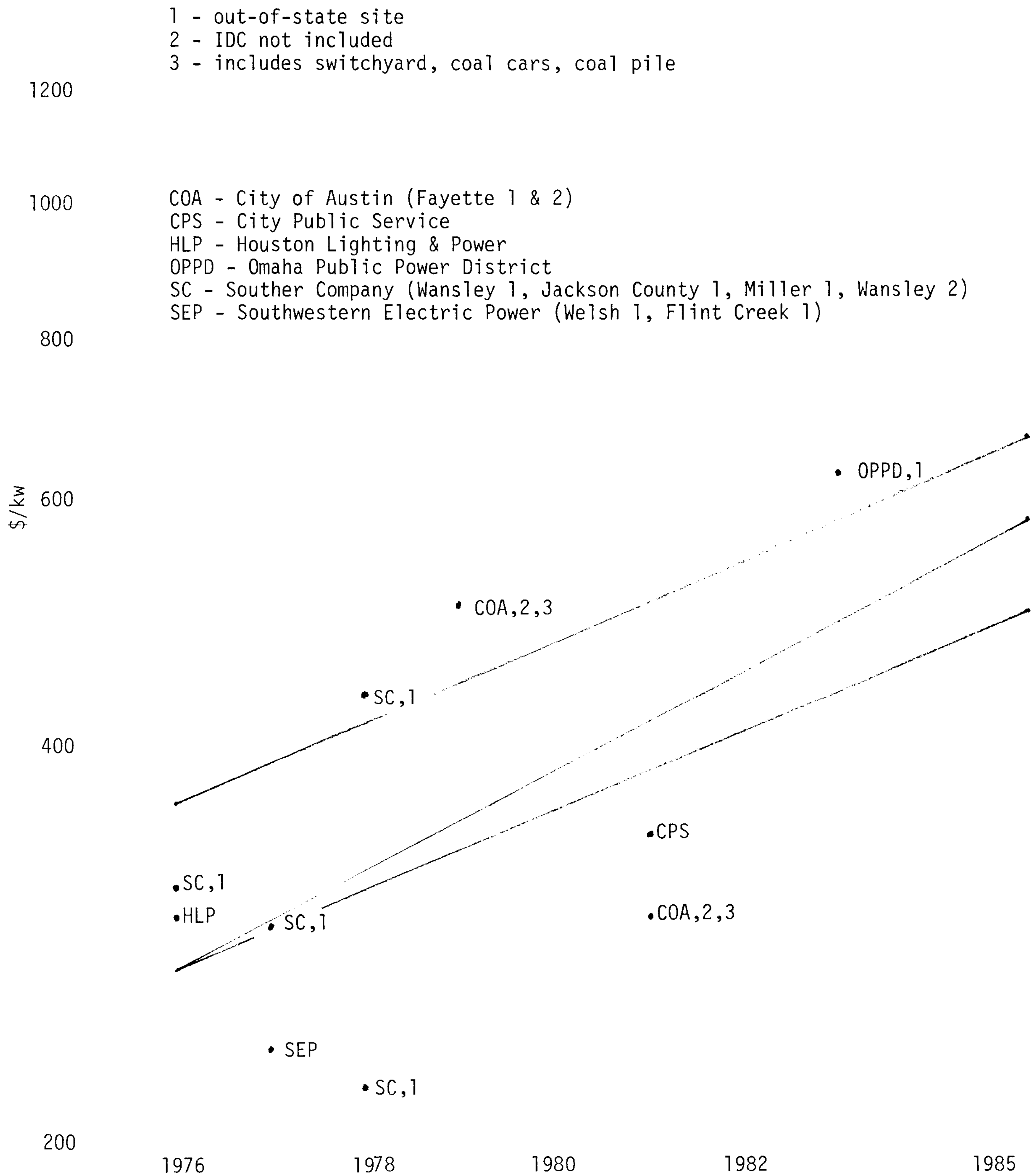

Table 3.53

COAL/LIGNITE PLANT CAPITAL COSTS - WITHOUT SCRUBBERS
(Dollars per kilowatt)

	1976	1980	1985
Average capital cost	275	360	505
High average capital cost	275	385	590
Worst-case average capital cost	365	480	680

Deflating individual costs at 7% back to 1976 dollars, the average in-state utility cost is \$286/kw with a standard deviation of \$53/kw. Since the sample of costs was primarily from higher cost areas, a \$275/kw average cost will be used. Inflating the 1976 average at 7% results in an expected average capital cost of \$505/kw in 1985. For the high average case, an additional \$85/kw (per point #6) results in a coal/lignite plant capital cost of \$590/kw in 1985. From figure 3.20 a worst-case average capital cost is indicated going from \$365 to 680/kw. Table 3.53 summarizes these data.

3.7.4 Other Plant Capital Costs

Although the Energy Supply and Environmental Coordination Act of 1974 effectively halts the future planning and construction of new oil and gas plants, there were some oil plants already planned at the time of passage of the act that were permitted to be constructed. For oil plants without scrubbers, the average capital cost is \$225/kw in 1976 and \$295/kw in 1980. For oil plants with scrubbers, the average capital cost is \$300/kw in 1976 and \$395/kw in 1980. It is assumed that there are no further oil plants constructed for base load purposes after 1980.

Several utilities within Texas are actively considering conversion of gas-fired plants to coal plants. For a gas plant to be considered for conversion it must meet three primary conditions:

1. The unit size must be large--at least 500 Mw(e)
2. The unit must be relatively new to ensure enough turbine generator life remaining to reasonably amortize the additional capital expense (commercial operation after 1970)

3. The unit must be located in an area where the environmental effects of a coal plant would not preclude the conversion

Although the cost of conversion has not been determined by actual experience, the conversion would consist of tearing down (scrapping the gas boiler) one boiler, then building a coal-fired boiler, adding the appropriate pollution control equipment, and finally reconnecting the piping to the turbine/feedwater system--steps which are farily well defined. Because the "rebuilt" coal plant would not require a turbine, generator, feedwater equipment, cooling equipment, certain control equipment, or some site preparation, the cost will be appreciably less than for a new coal plant. The estimated cost of gas to coal conversion would be $265/kw in 1980 and $350/kw in 1985. All conversions are assumed to be completed between 1980 and 1985 because of point 3 above.

3.7.5 Capital Costs Beyond 1985

Because of the large uncertainties in the cost and supply of materials, cost of equipment, labor costs, regulatory requirements, and the like, an accurate estimate of capital costs is impossible. Therefore all costs beyond 1985 are assumed to escalate at a 7% rate of inflation. Table 3.54 compares capital costs for differing types of plants to the year 2000 for Texas.

Table 3.54

AVERAGE CAPITAL COSTS TO 2000 FOR TEXAS
(Dollars per kilowatt)

	1976	1980	1985	1990	1995	2000
Nuclear						
Average	450	590	825	1160	1625	2280
High Average	450	610	900	1265	1770	2485
Worst-case average	600	790	1100	1545	2165	3035
Coal/Lignite with Scrubbers						
Average	325	425	600	845	1180	1655
High average	325	455	700	985	1380	1935
Worst-case average	435	570	800	1125	1575	2210
Coal/Lignite without Scrubbers						
Average	275	360	505	710	995	1395
High average	275	385	590	830	1160	1630
Worst-case average	365	480	680	955	1340	1880
Oil						
With scrubbers average	300	395	NA	NA	NA	NA
Without scrubbers average	225	295	NA	NA	NA	NA
Gas to Coal						
Average	NA	265	350	NA	NA	NA

NA - not applicable

INFORMATION SOURCES FOR SECTION 3.7

In-State Utilities

a. City of Austin Electric Department - telephone conversation between J.B. Gordon and G. Preston, July 13, 1976.

b. City Public Service (San Antonio) - O'Brien and Gere Engineers, Inc., analysis provided to San Antonio City Council, April 28, 1976.

c. El Paso Electric - Letter to J.B. Gordon from R. W. Waugh, Assistant to the Vice-President, June 22, 1976.

d. Gulf States Utilities - Letter to J.B. Gordon from A.J. Mary, Assistant to the Senior Vice-President, July 7, 1976.

e. Houston Lighting and Power - Letter to J.B. Gordon from D.E. Simmons, Vice-President, Corporate Planning, August 6, 1976.

f. Southwestern Electric Power - Letter to J.B. Gordon from L.E. Dillahunty, Mechanical Engineer, June 18, 1976.

g. Southwestern Public Service - Letter to J.B. Gordon from W.T. Seitz, System Planning, June 14, 1976.

h. Texas Utilities - Letter to J.B. Gordon from R.R. Parks, Director of System Planning, June 15, 1976.

Out-of-State Utilities

i. Omaha Public Power District - Coal/nuclear economics appraisal by OPPD, April, 1976.

j. Southern Company - Letter to J.B. Gordon from Donald E. Bennett, Jr., Financial Services, July 22, 1976.

CHAPTER 4

ALTERNATIVE FORECASTS OF ELECTRICITY SUPPLY AND COSTS

4.1 GUIDELINES FOR COMPARISON

For the purpose of comparison, the scenarios have been grouped so as to span a range of values in key assumptions. The medium growth base case is considered to be the most probable, but substantial uncertainty exist at present. To help understand the effects of these uncertainties, other scenarios with changes in assumptions are compared to the medium growth base case. Table 1 shows how the cases are best compared to highlight certain issues. The results of low and high demand growth scenarios are then discussed after results of the cases shown in Table 4.1 have been presented.

An item that needs to be mentioned at this stage is that tables presented in this chapter do not contain all the data relevant for a full-scale comparison. These results represent only the supply, demand and economic information. Chapters 5 and 6 then present the detailed environmental effects of the scenarios.

In the sections that follow, the results of the base case (deregulated gas) are first discussed. This is followed by discussions of comparisons among the various cases as indicated in Table 4.1.

4.2 BASE CASE

The quantitative results of the base case medium growth scenarios are presented in Table 4.2 for the years 1976, 1980, 1985, 1900, 1995 and 2000. The base case assumes deregulated gas prices. The demand growth rate assumed is five and one half percent per year between 1976 and 2000. This results in an electricity generation

TABLE 4.1

COMPARISON OF CASES

Basis for Comparison	Cases Compared
Gas Regulation	B, BR, 4
Air Quality Regulation	B, 2, 3, 6
Nuclear Constraints	B, 1, 3
Load Management	B, 5
Constrained Fuel Supply	B, 7, 4

B - Base Case

BR - Base Case (Regulated intrastate gas prices) requirement in Texas of 533 billion kwh in the year 2000.

Currently, electricity in Texas is generated almost exclusively by gas-fired plants. In the future, however, new gas-burning plants will not be built because of expected supply limitations. Under the base case assumptions, the new capacity coming on line is predominantly nuclear and coal/lignite. Nuclear capacity reaches the limit of 20 Gw (imposed on it by resource considerations) by 1990, after which only coal/lignite and oil-fired capacities are constructed.

The capacity and generation attributed to "coal/lignite" in Table 4.2 are combined coal and lignite numbers. The quantities labeled "lignite" correspond to those lignite plants already committed. As explained in an earlier chapter, the price of lignite is expected to reach levels that will make it competitive with coal. When this happens, coal and lignite plants will be indistinguishable in economic consequences. Therefore, it is not possible to specify how much of the new "coal" capacity is really lignite and how much is coal. The conditions that will determine the exact splits will be imposed by resource and environmental considerations. However, the capacity and generation numbers under the heading "lignite" correspond strictly to lignite fired-plants that either have been planned or are in various stages of completion.

Coal and lignite capacity and generation grow at a rate of about 9% per year between 1980 and 2000. By the year 2000, coal and lignite constitute about 42% of the total projected capacity and about 63% of the total generation. These figures imply that these plants will be predominantly base loaded. In addition, the growth implies addition of about 55 Gw of coal/

TABLE 4.2

BASE CASE
(5 1/2% Growth)

	1976	1980	1985	1990	1995	2000
Capacity (Gw(e))						
Nuclear	0.0	2.40	5.20	20.00	20.00	20.00
Coal/Lignite	0.32	4.55	9.71	14.20	26.92	45.24
Oil	1.73	1.86	2.31	6.34	13.32	21.10
Gas	31.70	29.73	24.12	18.14	15.42	13.58
Lignite	2.30	6.10	11.45	11.45	11.45	11.45
C.T.	1.75	1.82	4.72	8.09	14.52	22.19
TOTAL	37.80	46.47	57.51	78.23	101.63	133.55
Generation (Bkwh)						
Nuclear	0.0	15.37	33.30	128.07	128.07	128.07
Coal/Lignite	0.0	27.10	57.83	84.60	160.38	269.47
Oil	0.0	0.00	18.45	23.15	44.42	61.56
Gas	133.7	103.81	60.89	7.90	6.53	5.19
Lignite	13.7	36.34	68.22	68.22	68.22	68.22
C.T.	0.0	0.0	0.00	0.00	0.08	0.34
TOTAL	147.4	182.62	238.68	311.94	407.70	532.85
Fuel Consumption						
Uranium (million lb)	0.0	0.18	0.40	1.50	1.50	1.50
Coal/Lignite (million tons)	0.0	13.0	27.00	40.00	76.00	130.00
Oil (million bbls)	0.0	0.0	27.00	34.00	66.0	91.00
Gas (million mcf)	1200.0	940.0	550.0	72.00	59.0	47.00
Lignite (million tons)	10.0	27.0	50.0	50.00	50.0	50.00
Reserve Margin (percent)	16.80	15.88	9.74	14.21	13.54	14.16
Elec. Price (¢/kwh)	2.03	3.15	4.69	5.07	6.45	8.42

lignite capacity in the next 24 years, i.e., about 2.3 GW each year. This amounts to adding three plants of 750 MW each year on an average and is not beyond current capabilities. In the absence of other constraints coal and lignite consumption together would amount to about 180 million tons/year by the year 2000.

If it is assumed that all the coal/lignite will be mined in Texas, then the lignite mining industry in the state will have to expand tenfold in 20 years, necessitating a growth rate of about 12% per year. This growth rate is not impossible, but an analysis of historical growth patterns in the resource extraction industries indicates that such growth may very likely not be attainable. If the local mining industry is not capable of providing the coal and lignite, coal will have to be imported from states such as New Mexico, Wyoming, Montana. Our discussions with the railroad companies indicate that they do not foresee any rail transportation capability shortages. But since acceptable sites for coal-burning plants may not be near existing rail lines, additional track mileage might well be needed. This new track installation should be carefully planned if it is to offer the least disruption and most benefit to existing intrastate and interstate trade.

The burning of coal and lignite for producing electricity could create significant environmental and health hazards. Lignite has a fairly high ash content, and South Texas lignite is especially unsuitable for burning without expensive pollution abatement equipment. Our preliminary calculations indicate that the projected rate of burning 180 million tons of coal and lignite by the year 2000 could result in emission rates that are more than a hundred times higher than those today. These effects could result in significant deterioration of air quality and effect a reduction in the agricultural output of the state. Thses effects are discussed further in the following chapters.

Though the required coal and lignite plant construction is feasible, the problems in development of resources and/or environmental considerations could depress coal and lignite usage below values reported here. Alternate scenarios, where coal use is limited by higher costs are studied as supplementary cases (Cases 2 and 3).

Nuclear capacity is expected to grow rapidly between 1985 and 1990 until it reaches the limit imposed in the base case. During these five years, almost 15 Gw of new nuclear plant additions are made, amounting on an average of three plants each of 1000 Gw capacity coming on line each year. The capacity limit of 20 Gw imposed on nuclear power in this case is due to fuel resource limitations. Details as to how it was arrived at were presented in section 3. If this limit is not imposed and assuming that uranium prices do not reach exorbitant levels, nuclear capacity could continue to grow. The effects of such a possibility will be seen later when the results of Case 3 are discussed. In this case nuclear capacity is base loaded and is assumed to have a maximum capacity factor of 73%.

Oil capacity increases after 1990 when no new nuclear capacity is available. However, the kilowatt-hour generation from these plants is quite low, and they are primarily used as intermediate or peaking units.

In light of current emphasis on the enforcement of the Energy Supply and Environmental Coordination Act of 1974 (ESECA), the reduced use of oil is very likely.

The reserve margins as presented in Table 4.2 are at a fairly steady level of about 15%, except for 1985, when the margin drops to about 10%. The reason for this low value is that capacity declines fairly rapidly by 1985 as a result of the Texas Railroad Commission order forcing the reduction in use of natural gas as a boiler fuel in Texas (Docket No, #600). Further nuclear power plants committed today cannot be expected to come on line until at least 1986 because of the 10-year licensing and construction lead time. Finally, enforcement of ESECA by the Federal Energy Office could eliminate significant new oil plant construction. The only alternatives left, coal and lignite, do begin production quite rapidly (18 Gw coming on line between now and 1985), but not fast enough to avoid a drop in the reserve margin to 10% by 1985.

The average price of electricity escalates at an annual rate of about 6.1% between now and the year 2000. This rate is slightly higher than the assumed rate of inflation (5.5%) and is due to the slightly higher cost of generation that results from the increasing unavailability of cheap natural gas.

4.3 ALTERNATIVE GAS REGULATION POLICIES

Table 4.3 presents the results of the base case (B), the base case with regulated intrastate gas prices (BR), and the case in which gas consumption is forced to zero by 1985 (Case 4). All three cases presented have a medium demand growth assumption, i.e., 5-1/2% per year over the period 1976-2000. The base case assumes that the price of gas will be $3.40/mcf by 1985 (in 1976 dollars). In the regulated gas price case it is $1.42/mcf (in 1976 dollars), and in Case 4 it is $1.31/mcf (in 1976 dollars).

In the base case, gas consumption drops fairly rapidly and by 1990 the use of gas-burning plants is primarily for peaking. As the price of gas in Case BR is lower than that in the base case, the demand for gas ought to be higher. However, production of gas will be substantially lower, discouraged by its low regulated price. This serves to constrain gas use by the electric utility sector and in the long run, just as in the base case, natural gas is used primarily as a peaking fuel.

From Table 4.3 it can be seen that there is no difference at all in the capacity configurations of the two base cases. The reason is that the construction of new gas plants is mandatorily disallowed in both, and therefore the price of gas does not play any part in construction commitments. Moreover, the regulation/deregulation of natural gas in Texas is not assumed to affect the prices of coal, oil or nuclear fuel. As far as electricity generation is concerned, the long-term usuage of natural gas is the same in the regulated price case as in the base case. However, in the short run, i.e., around 1980, gas usage in case BR is slightly lower because of reduced gas availability. In the long run, the use of natural gas is not significantly affected by supply considerations because regulatory constraints serve to limit its usuage.

Case 4, which has gas consumption being forced to zero by 1985, assumes a gas price that is lower than the base case gas price. Gas use is reduced by the conversion of existing gas-fired capacity to coal- and oil-burning plants, gradually at first and then more rapidly later, until by 1985 gas usage drops to zero. Twenty five percent of the converted gas plants are assumed to burn coal, and the remaining oil. It is also assumed that the conversion will entail a loss of capacity of about 8%. Conversion from gas to coal firing is expected to cost $200/kw in 1976 dollars while conversion

TABLE 4.3

SUMMARY RESULTS OF ALTERNATIVE GAS REGULATION POLICIES

	1980			1990			2000		
	B	BR	4	B	BR	4	B	BR	4
CAPACITY (Gw(e))									
Nuclear	2.40	2.40	2.40	20.00	20.00	20.00	20.00	20.00	20.00
Coal	4.55	4.55	7.81	14.20	14.20	24.04	45.24	45.24	55.73
Oil	1.86	1.86	11.21	6.34	6.34	19.06	21.10	21.10	25.79
Gas	29.73	29.73	20.15	18.14	18.14	0.0	13.58	13.58	0.00
Lignite	6.10	6.10	6.10	11.45	11.45	11.45	11.45	11.45	11.45
C.T.	1.82	1.82	3.70	8.09	8.09	4.51	22.19	22.19	20.67
TOTAL	46.47	46.47	51.38	78.23	78.23	79.07	133.55	133.55	133.64
GENERATION (B-kwh)									
Nuclear	15.37	15.37	15.37	128.07	128.07	128.07	128.07	128.07	128.07
Coal	27.10	27.10	6.46	84.60	84.60	111.12	269.47	269.47	321.15
Oil	0.00	6.14	0.46	23.15	23.15	4.53	61.56	61.56	15.23
Gas	103.81	97.67	124.03	7.90	7.90	0.00	5.19	5.19	0.00
Lignite	36.34	36.34	36.34	68.22	68.22	68.22	68.22	68.22	68.22
C.T.	0.00	0.00	0.00	0.0	0.00	3.05	0.34	0.34	0.17
TOTAL	182.62	182.62	182.62	311.94	311.94	311.94	532.85	532.85	532.85
FUEL CONSUMPTION									
U_3O_8 (million lb)	0.18	0.18	0.18	1.50	1.50	1.50	1.50	1.50	1.50
Coal (million tons)	13.0	13.0	3.1	40.0	40.0	53.0	130.0	130.0	150.0
Oil (million bbls)	0.0	9.1	0.7	34.0	34.0	6.7	91.0	91.0	23.00
Gas (million mcf)	940.0	890.0	1100.0	72.0	72.0	0.0	47.0	47.0	0.00
Lignite (million tons)	27.0	27.0	27.0	50.0	50.0	50.0	50.0	50.0	50.0
Reserve Margin	15.88	15.88	28.13	14.21	14.21	15.44	14.16	14.16	14.23
Elec. Price (¢/kwh)	3.15	2.71	2.71	5.07	4.97	4.73	8.42	8.35	7.83

from gas to oil will cost $50/kw.

The conversion of gas-burning plants to coal- and oil-fired plants substantially reduces the use of natural gas in the early 1980s. By 1985 the conversions are complete, and by 1990 the coal and oil capacities in Case 4 are significantly higher than those in the base case. Coal and nuclear plants get base loaded while the oil-fired plants are used primarily for cycling and peaking. By 1990 in Case 4 we have about 10 Gw more of coal capacity as compared to the base case. Since this capacity gets base loaded it displaces some of the base case oil generation. Thus, in the long run oil consumption in Case 4 is only about one-fifth of the base case values. On the other hand coal and lignite consumption is higher by about 10%.

In the short run, the price of electricity is about 10% lower in the regulated gas price case as compared to the base case. However, by 1990 when gas use declines, the difference in price is insignificant. In Case 4, the price of electricity is lower than that in the base case because of the greater use of coal and lignite and reduced oil use.

4.4 ALTERNATIVE AIR QUALITY REGULATION

Four cases having alternative air quality regulations are compared in this section: (1) base case, (2) medium air quality - Case 2, (3) high air quality - Case 3, and (4) ground level air quality standards - Case 6.

The medium air quality case is designed to depict a situation in which lignite use is discouraged and coal use is allowed but only with improved pollution abatement equipment. Nuclear capacity is constrained to 20 Gw as in the base case.

The high air quality scenario discourges coal and oil as well as lignite use. Coal and lignite powered plants are assumed to be economically unattractive because pollution control equipment requirements increase their capital costs. Oil use is thwarted by permitting the burning of only desulfurized oil (0.1% S) which is assumed to cost $3.50 per barrel more (in 1975 dollars) than in the base case. In contrast to the previous cases, however, nuclear powered generation is not constrained but allowed to grow at the rate needed.

Case 6 represents the use of ground-level standards for air quality control. It is the opposite of the high air quality case with respect to type of fuel usage. This case permits the use of coal and lignite without scrubbers. Here air quality is monitored at the ambient level and coal/lignite burning is allowed as long as the ambient air quality meets the necessary standards. When the air quality deteriorates, oil has to be used instead of coal.

This method has been used in England and even in certain areas within the U.S. In practice this restriction translates to the use of oil in coal burning facilities 10% of the time. This feature is included in the model for the purpose of computing oil use and electricity prices. As scrubbers are not required, coal/lignite plant capital costs are lower than in the base case. The results of the four cases are presented in Table 4.4 for the years 1980, 1990, and 2000. Medium demand growth is assumed for all cases.

The medium air quality case (Case 2) results in a reduction in coal/lignite use to almost half that of the base case by the year 2000, constituting only 25% of the total capacity. Most of it shifts expectedly to oil capacity, which doubles as compared to the base case. More significantly, the usage factor of oil capacity increases resulting in an oil demand that is more than three times that of the base case. The constrained coal/lignite demands amounts to 117 million tons in this case as compared to the base case demand of 180 million tons by the year 2000. Oil demand on the other hand rises to 280 million barrels, an increase of 190 million barrels over the corresponding base case consumption. Consequently, by 2000 the price of electricity in Case 2 is 9% higher than the base case price.

Case 3, the high air quality case, having no constraints on nuclear growth results in nuclear capacity growing to 77 Gw by 2000. The nuclear capacity appears in lieu of coal and oil capacities which are predominant in the base case. In the shorter term until 1990 the difference between this case and the base case is not significant. As compared to the medium air quality scenario (Case 2) this case has significantly less oil use

TABLE 4.4

ALTERNATIVE AIR QUALITY SCNEARIOS

	1980				1990				2000			
	B	2	3	6	B	2	3	6	B	2	3	6
CAPACITY (Gw(e))												
Nuclear	2.40	2.40	2.40	2.40	20.00	20.00	24.36	20.00	20.00	20.00	76.76	20.00
Coal	4.55	4.55	4.55	4.55	14.20	12.71	12.71	19.90	45.24	23.67	13.28	76.74
Oil	1.86	1.86	1.86	1.86	6.34	7.87	2.36	1.45	21.10	37.67	4.41	1.12
Gas	29.73	29.73	29.73	29.73	18.14	18.14	18.14	18.14	13.58	13.58	13.58	13.58
Lignite	6.10	6.10	6.10	6.10	11.45	11.45	11.45	11.45	11.45	11.45	11.45	11.45
C.T.	1.82	1.82	1.82	1.82	8.09	9.13	9.71	5.43	22.19	27.35	14.22	9.18
TOTAL	46.47	46.47	46.47	46.47	78.23	79.31	78.73	76.37	133.55	133.72	133.71	132.07
GENERATION (B-kwh)												
Nuclear	15.37	15.37	15.37	15.37	128.07	128.07	156.02	128.07	128.07	128.07	491.51	128.07
Coal	27.10	27.10	27.10	27.10	84.60	75.70	75.28	107.06	269.47	140.99	10.85	335.70
Oil	0.00	0.0	0.0	0.0	23.15	32.10	3.21	1.62	61.56	186.12	1.85	0.23
Gas	103.81	103.81	103.81	103.81	7.90	7.85	9.21	7.02	5.19	8.11	1.49	0.63
Lignite	36.34	36.34	36.34	36.34	68.22	68.22	68.22	68.22	68.22	68.22	27.15	68.22
C.T.	0.00	0.0	0.00	0.0	0.0	0.0	0.00	0.0	0.34	1.34	0.0	0.00
TOTAL	182.62	182.62	182.62	182.62	311.94	311.94	311.94	311.94	532.85	532.85	532.85	532.85
FUEL CONSUMPTION												
U_3O_8 (million lbs)	0.18	0.18	0.18	0.18	1.50	1.50	1.90	1.50	1.50	1.50	5.90	1.50
Coal (million tons)	13.0	13.0	13.0	12.0	40.0	36.0	36.0	46.0	130.0	67.0	5.2	140.0
Oil (million bbls)	0.0	0.0	0.0	3.6	34.0	48.0	4.8	17.0	91.0	280.0	2.7	45.0
Gas (million mcf)	940.0	940.0	940.0	940.0	72.0	71.0	84.0	64.0	47.0	74.0	14.0	5.8
Lignite (million tons)	27.0	27.0	27.0	27.0	50.0	50.0	50.0	50.0	50.0	50.0	20.0	50.0
Reserve Margin	15.88	15.88	15.88	15.88	14.21	15.80	14.96	11.51	14.16	14.30	14.29	12.89
Elec. Price (¢/kwh)	3.15	3.15	3.26	3.14	5.07	5.16	5.15	4.94	8.42	9.14	7.55	8.09

because a major portion of the fossil fueled generation of Case 2 is replaced by nuclear generation. Nuclear constitutes 92% of the total generation by the year 2000 in the high air quality case. The net result is an electricity price that is more than 10% lower than the base case price. In fact this case has the lowest electricity price in the long run as compared to other cases. The central question, however, is whether or not uranium resources will be available to support the fuel requirements of this case.

When ground level standards are assumed for air quality monitoring, coal/lignite appears to be the most economical after nuclear. Installed nuclear capacity is constrained in this case to be no larger than the base case value. When this is reached, coal/lignite plant construction dominates new commitments, and by the year 2000 their combined capacity is projected to be 87 Gw, or 66% of total capacity. Electricity generation from these plants amounts to 76% of the total generation in 2000. However, coal/lignite consumption is only 6% higher than that in the base case. The reason is that 10% of the electricity generated from coal/lignite plants is assumed to result from oil firing. Therefore, even though the electricity generation number under oil plants is insignificant in this case, oil consumption is half of the base case value. By the year 2000 the price of electricity is only about 4% lower in this case when compared to the base case.

4.5 ALTERNATIVE NUCLEAR POLICIES

Table 4.5 presents the quantitative results of three cases (Base, Case 1, and Case 3) that represent alternative nuclear policy scenarios under medium demand growth. The base case assumes that nuclear growth will continue as long as there is uranium available to fuel the light water reactors (LWRs). Assuming that present rates of exploration continue there will only be enough uranium available to fuel about 20 Gw of LWRs in Texas. Therefore in the base case we constrain nuclear generating capacity to 20 Gw.

In Case 1 the basic assumption is that there will be no additional nuclear capacity commitments beyond those already made. This sets a limit to nuclear generating capacity in Texas at 9900 Mw, which includes the nuclear power that will be imported from neighboring states. Case 3 is a high air quality case which has no resource constraints on nuclear growth. In addition, higher fossil plant capital costs and fuel costs tend to encourage nuclear power plant construction. Thus we have three alternative nuclear scenarios, two of which have supply constraints on nuclear power and one of which encourages nuclear growth.

The unconstrained nuclear case (Case 3) has nuclear capacity growing to more than 75 Gw by the year 2000. The generation from these plants is about 490 billion kwh, amounting to more than 90% of the electricity generated in Texas. This compares with nuclear capacity of 20 Gw in the base case and 9.9 Gw in Case 1. Nuclear generation numbers are also substantially lower in constrained nuclear cases, corresponding to 24% and 12% of total generation for the base case and Case 1 respectively.

The unconstrained nuclear case has less than half the lignite consumption of the other two cases and almost negligible coal and oil consumption. The rate of uranium consumption in this case, however, is about 6 million pounds of uranium (approximately 18,000 tons of U_3O_8)

TABLE 4.5

ALTERNATIVE NUCLEAR POLICIES

	1980			1990			2000		
	B	1	3	B	1	3	B	1	3
CAPACITY (Gw(e))									
Nuclear	2.40	2.40	2.40	20.00	9.90	24.36	20.00	9.90	76.76
Coal	4.55	4.55	4.55	14.20	17.58	12.71	45.24	51.39	13.28
Oil	1.86	1.86	1.86	6.34	9.07	2.36	21.10	23.90	4.41
Gas	29.73	29.73	29.73	18.14	18.14	18.14	13.58	13.58	13.58
Lignite	6.10	6.10	6.10	11.45	11.45	11.45	11.45	11.45	11.45
C.T.	1.82	1.82	1.82	8.09	10.71	9.71	22.19	23.71	14.22
TOTAL	46.47	46.47	46.47	78.23	76.85	78.73	133.55	133.93	133.71
GENERATION (B-kwh)									
Nuclear	15.37	15.37	15.37	128.07	63.40	156.02	128.07	63.40	491.51
Coal	27.10	27.10	27.10	84.60	104.70	75.28	269.47	306.09	10.85
Oil	0.00	0.0	0.0	23.15	62.41	3.21	61.56	88.81	1.85
Gas	103.81	103.81	103.81	7.90	13.12	9.21	5.19	5.84	1.49
Lignite	36.34	36.34	36.34	68.22	68.22	68.22	68.22	68.22	27.15
C.T.	0.0	0.0	0.0	0.0	0.10	0.00	0.34	0.49	0.0
TOTAL	182.62	182.62	182.62	311.94	311.94	311.94	532.85	532.85	532.85
FUEL CONSUMPTION									
U_3O_8 (million lb)	0.18	0.18	0.18	1.50	0.76	1.90	1.50	0.76	5.90
Coal (million tons)	13.0	13.0	13.0	40.0	50.0	36.0	130.0	150.0	5.2
Oil (million bbls)	0.0	0.0	0.0	34.0	93.0	4.8	91.0	130.0	2.7
Gas (million mcf)	940.0	940.0	940.0	72.0	120.0	84.0	47.0	53.0	14.0
Lignite (million tons)	27.0	27.0	27.0	50.0	50.0	50.0	50.0	50.0	20.0
Reserve Margin	15.88	15.88	15.88	14.21	12.20	14.96	14.96	14.49	14.29
Elec. Price (¢/kwh)	3.15	3.15	3.26	5.07	5.34	5.15	8.42	8.85	7.55

per year by the year 2000, which is four times as high as that in the base case. Significant increases in exploratory drilling for uranium would have to take place if this were to become a reality.

In Case 1 it is assumed that no new nuclear plant construction is undertaken beyond those plants already planned, resulting in 9.9 Gw total nuclear capacity installed. Here the major increase in generation capacity is in coal/lignite, which rises to about 63 Gw by the year 2000. Electricity generation from these fuels rises to about 374 billion kwh by that time, or about 70% of the total. As a consequence, coal/lignite consumption rises to 200 million tons as compared to 180 million tons in the base case and 25 million tons in the unconstrained nuclear case.

In the long run, Case 3 (the high air quality case without nuclear constraints) results in the lowest price of electricity in spite of the higher fuel and capital costs of the fossil-fueled plants. By the year 2000, Case 3 has an electricity price that is about 10% lower than that in the base case and 15% lower than that in Case 1. In the short run, however, the prices in Case 3 are higher because nuclear plants do not constitute a major fraction of the capacity until after 1990 and relatively expensive coal/lignite has to be used to meet the demand.

4.6 CONSTRAINED FUEL SUPPLY

Case 7 as described earlier is an extreme version of constrained fuel supply. This is the so called "worst case" scenario that has either supply or regulatory restrictions on almost all fuel sources. Case 4, the one in which gas consumption is reduced to zero by 1985, can be considered to be a case with major constraints, as natural gas is a principal component of fuel used for generating electricity in Texas. This section compares the quantitative results of these two constrained supply cases (mainly Case 7) with the base case.

The numerical results of the three cases, (base, Case 7, and Case 4) are shown in Table 4.6 for the years 1980, 1990, and 2000. Electricity demand for all three is assumed to grow at 5-1/2% per year, which corresponds to the medium growth scenario. Case 7 has natural gas policies as in Case 4, air policies as in Case 3 (high air quality), nuclear fuel availability as in the base case, and an additional constraint on oil use that represents enforcement of the Energy Security and Environmental Coordination Act of 1974. The above assumptions imply the following: natural gas price will be only $1.31/mcf (in 1975 dollars), but supply limited oil price will be higher by $3.50/bbl (in 1975 dollars) as compared to the base case, nuclear capacity will be constrained to 20 Gw, and no new oil capacity commitments will be made. In addition, capital costs of pollution abatement equipment for coal and lignite plants will be higher than in the base case.

In the short run, the "worst case" (Case 7) situation causes gas plant capacity to drop to 20 Gw, which is the same as in Case 4. However, unlike Case 4, no new oil plants are built because of ESECA enforcement, and this causes the reserve margin to drop to 10% in 1980. At the same time, because of the rapidly declining gas capacity and no new construction of oil plants, the only alternatives left are coal/lignite, nuclear, and combustion turbines. As nuclear plants have a construction lead time of 10 years and coal/lignite of 5 years, the only generation alternative available in the short term is combustion turbines. In 1980 the combustion turbine

TABLE 4.6

CONSTRAINED FUEL SUPPLY

	1980			1990			2000		
	B	7	4	B	7	4	B	7	4
CAPACITY (Gw(e))									
Nuclear	2.40	2.40	2.40	20.00	20.00	20.00	20.00	20.00	20.00
Coal	4.55	4.55	7.81	14.20	17.30	24.04	45.24	67.22	55.73
Oil	1.86	1.86	11.21	6.34	1.45	19.06	21.10	1.12	25.79
Gas	29.73	20.18	20.15	18.14	0.00	0.0	13.58	0.00	0.00
Lignite	6.10	6.10	6.10	11.45	11.45	11.45	11.45	11.45	11.45
C.T.	1.82	9.40	3.70	8.09	27.31	4.51	22.19	32.63	20.67
TOTAL	46.47	44.50	51.38	78.23	77.51	79.07	133.55	132.55	133.64
GENERATION (B-kwh)									
Nuclear	15.37	15.37	15.37	128.07	128.07	128.07	128.07	128.07	128.07
Coal	27.10	4.79	6.46	84.60	103.03	111.12	269.47	331.61	321.15
Oil	0.00	1.10	0.46	23.15	2.54	4.53	61.56	0.68	15.23
Gas	103.81	124.0	124.03	7.90	0.00	0.00	5.19	0.0	0.00
Lignite	36.34	36.34	36.34	68.22	68.22	68.22	68.22	68.22	68.22
C.T.	0.0	0.99	0.00	0.0	10.09	3.05	0.34	4.27	0.17
TOTAL	182.62	182.62	182.62	311.94	311.94	311.94	532.85	532.85	532.85
FUEL CONSUMPTION									
U_3O_8 (million lb)	0.18	0.18	0.18	1.50	1.50	1.50	1.50	1.50	1.50
Coal (million tons)	13.0	2.30	3.1	40.0	49.0	53.0	130.0	160.0	150.0
Oil (million bbls)	0.0	1.60	0.7	34.0	3.8	6.7	91.0	1.0	23.00
Gas (million mcf)	940.0	1100.0	1100.0	72.0	0.0	0.0	47.0	0.0	0.00
Lignite (million tons)	27.0	27.0	27.0	50.0	50.0	50.0	50.0	50.0	50.0
Reserve Margin	15.88	10.97	28.13	14.21	13.16	15.44	14.16	13.19	14.23
Elec. Price (¢/kwh)	3.15	3.01	2.71	5.07	5.85	4.73	8.42	9.28	7.83

capacity is 9.4 Gw as compared to 1.8 Gw in the base case and rises to more than 27 Gw by 1990 as opposed to 8 Gw in the base case. In Case 7, as soon as the utilities realize the capacity problems they will be faced with as a result of constraints on gas and oil use, they commit as much nuclear capacity as they can and the resource imposed limit on nuclear capacity (of 20 Gw) is reached around 1986, much earlier than in the base case. Simultaneously coal capacity commitments are also increased compared to the base case to provide 3 Gw more by 1990. By the year 2000, coal capacity is projected to be 67 Gw in Case 7 as compared to 45 Gw in the base case, and it constitutes 50% of the total capacity. Oil capacity in this case is only 1 Gw as compared to 21 Gw in the base case and 26 Gw in Case 4 by the year 2000. On the generation side coal provides about 62% of the total in Case 7 as compared to 50% in the base case and 60% in Case 4. Generation from oil plants is negligible.

As a result of these generation mixes the demand for coal/lignite rises to 210 million tons by 2000 as compared to 180 million tons in the base case. However, oil demand by that time is as low as 1 million barrels as compared to the base case demand of 91 million barrels. It should be noted at this stage that coal and lignite are being used not so much for their economy as for the reason that they are the only available resource. The costs of pollution abatement equipment are assumed to be fairly high. Consequently, the price of electricity by the year 2000 is projected to be 9.28¢/kwh, which is more than 10% higher than the corresponding base case price.

The results show that the demand for coal and lignite will be very high. This fact is sure to cause problems in the areas of coal availability and transportation capability, not to mention the environmental hazards and the high capital requirements of pollution control equipment. The ability to meet the new capacity demand caused by the rapidly declining gas capacity in the face of restrictions on the use of most of the fuel resources is highly uncertain.

4.7 LOAD MANAGEMENT

Load management policies are inspired by the desire to more efficiently use existing capability and aim towards improving the load factors of service areas. Load (or utilization) factors depend on the configuration of customers and on consumption habits. A region that is heavily industrialized will normally have a load factor that is higher than one that is predominantly residential. In the past, the aggregate load factor in Texas has been below the national average.

One additional scenario (Case 5) has been simulated to help analyse the economic impact of a major improvement in the aggregate load factor of utilities in Texas. The load factor is assumed to rise to 68% by 1980 and stay at that level indefinitely. The results of this case are compared to those of the base case (deregulated gas price) and are presented in Table 4.7. Medium demand growth, at 5 1/2% per year, is assumed for both cases.

Since new capacity will not be needed as soon under the assumptions of successful load management, in this case it has been assumed that electric utilities will postpone by two years the construction of plants already committed. The postponement is assumed to occur after 1977. Thus plants that were formerly scheduled to come on line in 1978 would do so in 1980 and so on. This assumption is implemented to prevent the occurrence of extremely high reserve margins caused by a flattening of the load curve. Its validity is dependent upon the utilities correctly forecasting improved load factors and adjusting their plant expansion schedules accordingly.

In the long run, the flattening out of load curves will reduce capacity requirements and hence the rate base. Also, flatter load curves would imply that a larger proportion of total capacity should be base loaded. Therefore, the price of electricity could be expected to be lower in the long run due to lower "net revenue requirements" and operating costs. However, in the short and medium term, this will not happen, and the medium term extends to 25 years or more into the future. Texas has a large percentage of gas-fired capacity which will not be out of commission for quite some time. If capacity requirements do not increase as planned, then (because of flattened load curves) new capacity already planned will not necessarily have to be completed on schedule. As most of this new capacity is expected to be coal/lignite and nuclear, its postponement or cancellation makes the generation mix relatively more dependent on existing capacity which is largely gas-fired. Therefore, the rate base can be expected to be smaller than that in the base case, but the cost of generation would be considerably higher due to the higher fuel costs. The higher fuel costs offset at least part of the reduction in other revenue requirements in the short run.

The model simulation bears this out as can be seen in Table 4.7. In 1980 though, the reduced rate base is only partly offset by the increased

TABLE 4.7

LOAD MANAGEMENT

	1977		1980		1990		2000	
	B	5	B	5	B	5	B	5
CAPACITY (Gw(e))								
Nuclear	0.0	0.0	2.40	0.0	20.00	6.99	20.00	20.00
Coal	1.26	1.26	4.55	1.92	14.20	13.30	45.24	30.33
Oil	1.69	1.69	1.86	1.56	6.34	5.14	21.10	14.24
Gas	32.08	32.08	29.73	29.73	18.14	18.14	13.58	13.58
Lignite	3.05	3.05	6.10	4.55	11.45	11.45	11.45	11.45
C.T.	1.75	1.75	1.82	1.75	8.09	5.00	22.19	12.96
TOTAL	39.83	39.83	46.47	39.52	78.23	60.01	133.55	102.57
GENERATION (B-kwh)								
Nuclear	0.0	0.0	15.37	0.0	128.07	44.75	128.07	128.07
Coal	0.0	0.0	27.10	11.45	84.60	79.20	269.47	180.07
Oil	0.0	0.0	0.00	0.0	23.15	41.05	61.56	113.97
Gas	137.3	137.3	103.81	144.06	7.90	78.72	5.19	42.10
Lignite	18.2	18.2	36.34	27.11	68.22	68.22	68.22	68.22
C.T.	0.0	0.0	0.0	0.0	0.0	0.00	0.34	0.00
TOTAL	155.5	155.5	182.62	182.62	311.94	311.94	532.85	532.85
FUEL CONSUMPTION								
U_3O_8 (million lb)	0.0	0.0	0.18	0.0	1.50	0.54	1.50	1.50
Coal (million tons)	0.0	0.0	13.0	5.4	40.0	38.0	130.0	86.0
Oil (million bbls)	0.0	0.0	0.0	0.0	34.0	61.0	91.0	170.0
Gas (million mcf)	1200.0	1200.0	940.0	1300.	72.0	720.0	47.0	380.0
Lignite (million tons)	13.0	13.0	27.0	20.0	50.0	50.0	50.0	50.0
Reserve Margin (%)	16.65	31.0	15.88	29.9	14.21	14.58	14.16	14.66
Elec. Price (¢/kwhr)	2.26	2.26	3.15	2.97	5.07	5.71	8.42	8.44
Cost of Gen. (¢/kwhr)	1.07	1.07	1.56	1.78	2.09	3.50	4.01	4.71
Rate Base (billion dollars)	7.5	7.5	12.6	8.0	46.9	29.7	119.8	95.8

cost of generation and hence the price of electricity is only slightly lower. However, by 1982 the price of electricity in Case 5 is higher than that in the base case and by 1990 rises to 5.71 ¢/kwhr, which is about 13% higher than the base case value. Further examination reveals that in 1990, even though the rate base in Case 5 is only 63% of that in the base case, the cost of generation is 67% higher, which results in the higher price of electricity. Even beyond 1990, right up to the year 2000 the price of electricity remains higher in Case 5 as compared to the base case. However, in the last decade the difference begins to decline till in 2000 the price in Case 5 is only marginally higher than that in the base case. It is around this time that the existing gas-fired capacity has dwindled to a small fraction of total capacity and the higher generation costs are offset by the reduced rate base. In spite of the postponement of new capacity by two years, the reserve margin in Case 5 rises to more than 30% around 1977. It later steadily declines to around 15% by 1990.

One problem that the load management scenario poses is in the area of natural gas consumption. We have assumed that natural gas prices will be deregulated and that there will be no artificial constraints placed on its consumption. However, inspite of the high gas prices ($3.40/mcf by 1985, in 1976 dollars) natural gas use is substantial, amounting to 720 million mcf/year in 1990. This would be in violation of the Texas Railroad Commission's order restricting future natural gas use. Unless the regulatory environment is such that it is worthwhile to scrap existing gas plants and build coal and nuclear instead load management could serve merely to prolong the utility's dependence on natural gas and oil. Scrapping large amounts of functional but high fuel cost capacity could cause short term increases in electricity prices due to the expense incurred, but it would be offset by a more rapid shift to non-petroleum fuel resources - cheaper in the long run.

4.8 ALTERNATIVE GROWTH SCENARIOS

The base case assumption for electricity demand growth is 5 1/2% per year. This section studies the effects that alternative growth scenarios would have on electric supply in Texas. There are two growth alternatives that are considered, the high case (7% per year) and the low (4% per year). Tables 4.8, 4.9, and 4.10 present the supply outcomes of the three growth scenarios for the years 1980, 1990, and 2000.

In the short run, i.e., by 1980, there are no significant differences between the three cases. The capacity configurations are almost the same except for an additional 412 MW of combustion turbine capacity in the high growth case. The result of the alternative growth rates is seen markedly in the 1980 reserve margin values, which vary from 7.42% in the high growth case to 26.28% in the low one. Electricity prices are almost identical, the low case having a slightly higher price because of the high reserve margin that appears in the short run.

By 1990 other differences become more apparent. Generation requirements vary from 248.07 billion kilowatt-hours in the low growth case to 391.0 billion kilowatt-hours in the high one. Capacity configurations are also different. Nuclear capacity reaches its limit of 20 Gw in both the medium and the high growth cases, whereas it is still 12 Gw in the low growth case. Coal/lignite capacity in the high case is 90% higher than in the low case, and the combined coal/lignite requirements for the two case are 110

TABLE 4.8

ALTERNATIVE GROWTH SCENARIOS - BASE CASE

1980

	MEDIUM (5 1/2%)	HIGH (7%)	LOW (4%)
CAPACITY (Gw(e))			
Nuclear	2.40	2.40	2.40
Coal/Lignite	4.55	4.55	4.55
Oil	1.86	1.86	1.86
Gas	29.73	29.73	29.73
Lignite	61.0	6.10	6.10
C.T.	1.82	2.23	1.82
TOTAL	46.47	46.88	46.47
GENERATION (B-kwh)			
Nuclear	15.37	15.37	15.37
Coal/Lignite	27.10	27.10	27.10
Oil	0.00	0.02	0.00
Gas	103.81	119.93	88.77
Lignite	36.34	36.34	36.34
C.T.	0.0	0.00	0.00
TOTAL	182.62	198.76	167.59
FUEL CONSUMPTION			
Uranium (10^6/lbs)	0.18	0.18	0.18
Coal (10^6/tons)	13.0	13.0	13.0
Oil (10^6/bbls)	0.0	0.03	0.0
Gas (10^6/mcf)	940.0	1100.0	810.0
Lignite (10^6/tons)	27.0	27.0	27.0
Reserve Margin	15.88	7.42	26.28
Elec. Price (¢/kwh)	3.15	3.10	3.21

TABLE 4.9

ALTERNATIVE GROWTH SCENARIOS - BASE CASE

1990

	MEDIUM (5 1/2%)	HIGH (7%)	LOW (4%)
CAPACITY (Gw(e))			
Nuclear	20.00	20.00	12.08
Coal/Lignite	14.20	21.55	12.71
Oil	6.34	11.16	4.37
Gas	18.14	18.14	18.14
Lignite	11.45	11.45	11.45
C.T.	8.09	15.46	5.82
TOTAL	78.23	97.77	64.58
GENERATION (B-kwh)			
Nuclear	128.07	128.07	77.37
Coal/Lignite	84.60	128.38	75.70
Oil	23.15	55.26	19.64
Gas	7.90	10.89	7.14
Lignite	68.22	68.22	68.22
C.T.	0.00	0.18	0.00
TOTAL	311.94	391.00	248.07
FUEL CONSUMPTION			
Uranium (10^6/lbs)	1.50	1.50	0.93
Coal (10^6/tons)	40.0	61.00	36.00
Oil (10^6/bbls)	34.0	82.00	29.00
Gas (10^6/mcf)	72.0	99.00	65.00
Lignite (10^6/tons)	50.00	50.00	50.00
Reserve Margin	14.21	13.88	18.57
Elec. Price (¢/kwh)	5.07	5.42	5.03

TABLE 4.10

ALTERNATIVE GROWTH SCENARIOS - BASE CASE

2000

	MEDIUM (5 1/2%)	HIGH (7%)	LOW (4%)
CAPACITY (Gw(e))			
Nuclear	20.00	20.00	20.00
Coal/Lignite	45.24	76.11	24.3
Oil	21.10	35.58	11.34
Gas	13.58	13.58	13.58
Lignite	11.45	11.45	11.45
C.T.	22.19	35.94	12.01
TOTAL	133.55	192.66	92.70
GENERATION (B-kwh)			
Nuclear	128.07	128.07	128.07
Coal/Lignite	269.47	453.35	144.83
Oil	61.56	112.81	22.09
Gas	5.19	5.58	4.00
Lignite	68.22	68.22	68.22
C.T.	0.34	1.12	0.0
TOTAL	532.85	769.16	367.20
FUEL CONSUMPTION			
Uranium (10^6/lbs)	1.50	1.50	1.50
Coal (10^6/tons)	130.0	220.0	69.0
Oil (10^6/bbls)	91.0	170.0	33.0
Gas (10^6/mcf)	47.0	51.0	36.0
Lignite (10^6/tons)	50.0	50.0	50.0
Reserve Margin	14.16	14.09	14.98
Elec. Price (¢/kwh)	8.42	9.12	7.60

million tons and 86 billion tons, respectively. Oil consumption is also considerably higher in the high growth case, amounting to 82 million barrels as opposed to 29 million barrels in the low growth scenario. The increased use of expensive fuels such as oil and gas and a relatively larger rate base caused by the building of expensive coal/lignite and nuclear plants causes the electricity price to be about 4 mills/kwh. higher in the high growth case than in the low growth case. By this time the reserve margins stabilize to around 15%.

By the year 2000, the reserve margins further stablize. At this time the high growth case has generation and capacity requirements that are more than twice those of the low growth case. All cases have installed nuclear capacity to the limit imposed and new capacity additions are predominantly coal/lignite and oil. The high growth case has a coal/lignite requirement of 270 million tons and an oil demand of 170 million barrels, compared to the low growth case demand of 119 million tons and 33 million barrels respectively. The result of this is to cause the price of electricity to rise to 9.12¢/kwhr in the high growth case, compared to only 7.60¢/kwhr in the low growth case.

An important consideration in review of these cases is the fact that all scenarios have exogenous electricity demand requirements and assume no price response. That is, the demand for electricity is not at all influenced by the price of electricity in these cases whereas in reality there is dependence between demand and price. What these results indicate is that if conservation measures cause the demand for electricity to drop, its price would not rise at the rate it otherwise would have, making electricity available at cheaper rates. The effect of this would likely be a price induced increase in electricity demand. This would then be followed by a price response, and so on.

The absence of an interacting electricity demand model with the supply model used is a shortcoming of this study. Bracketing demand growth by exogenous demand growth rates is a compromise and not as sophisticated as a detailed study that includes price sensitive demand functions. Suggestions for development of such functions are given in the recommendations for further research.