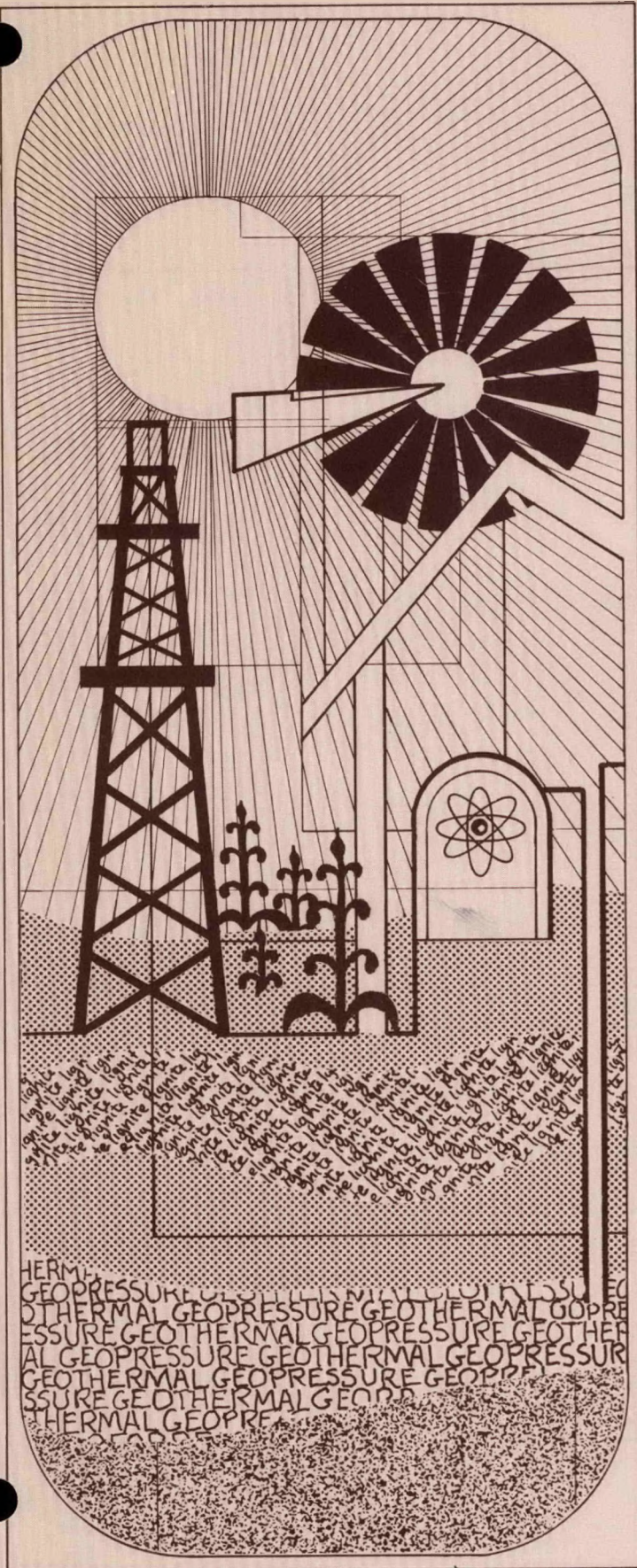


Texas Energy Development Fund

ENVIRONMENTAL/REGULATORY
ANALYSIS OF
MEDIUM-BTU
LIGNITE GASIFICATION
FOR INDUSTRIAL USE

TENRA
EDF - 039

TEXAS ENERGY
& NATURAL RESOURCES
ADVISORY COUNCIL
March, 1981



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ENVIRONMENTAL/REGULATORY ANALYSIS OF
MEDIUM-BTU LIGNITE GASIFICATION
FOR INDUSTRIAL USE

Radian Corporation
8501 Mo-Pac Boulevard
Austin, Texas 78766

FINAL REPORT

March 10, 1981

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EXECUTIVE SUMMARY

The rising cost of natural gas and oil has focused increased attention on the production and use of synthetic fuels. Because of Texas' historical dependence on natural gas,¹ major interest exists in the potential for substituting medium-Btu gas (MBG) produced from Texas lignite. Such a synthetic fuel is expected to be of special importance to industries located along the Gulf Coast due to financial, logistical, and environmental problems which may restrict direct conversion to lignite. Because of the newness of coal gasification technology application in the U.S. and in Texas, however, the introduction of MBG technology may be constrained by limitations in environmental information and regulatory procedures.

The objective of this report is the identification of gaps and conflicts in existing regulations which may influence the course of industrial lignite utilization in Texas and the maintenance of environmental quality. Topics addressed in the report include:

- Environmental impacts likely to be encountered from industrial lignite use;
- Environmental factors associated with gasification and direct firing of lignite which may need to be considered in decision-making affecting the course of lignite utilization;

¹Excluding the transportation sector, 76 percent of all energy used in Texas during 1978 was natural gas; seven percent was coal or lignite.

- Existing state and federal framework for regulating industrial use of lignite; and
- Regulatory gaps, conflicts, and constraints which may inhibit public and private industry initiatives to pursue the synfuels option.

In seeking to accomplish this objective, the report compares and contrasts the major environmental impacts and regulatory requirements associated with two alternatives for industrial use of lignite. The first alternative (or "scenario") assumes that lignite is converted to MBG in a mine-mouth Lurgi gasification plant and shipped by pipeline to coastal industry where it is used in existing industrial boilers originally built to use natural gas. The selection of the Lurgi process is of significance to the analysis 1) because it is the most likely technology to be used for the gasification of Texas lignite during the next ten years and 2) because of its operating characteristics, it encompasses a wider range of environmental impacts and related regulatory issues than other commercially available gasification processes. The second scenario assumes the transportation of lignite by rail to coastal industry and the construction of new boilers designed specifically to burn lignite. In both scenarios, the quantity of energy delivered to the Gulf Coast is 150 billion Btu per day (equal to roughly 2.5 percent of Texas industrial use of natural gas in 1978). Hypothetical sites were developed for the study to assist in better defining potential impacts and constraints.

The major environmental distinction between the two scenarios is in the location of impacts. The two greatest impacts affecting development are the air quality impacts associated with direct firing of lignite along the Gulf Coast and the socioeconomic impacts occurring in the lignite region during the construction of the gasification facility. Other significant areas of environmental impact and/or uncertainty are the disposal of gasification facility wastewaters and the disposal of solid wastes under both scenarios. As an example of the distinction in the location of impacts between the two scenarios, solid wastes in the MBG scenario total 1.36 million tons per year and occur exclusively at the mine-mouth gasification facility, whereas solid wastes under the direct use scenario, totalling 1.15 million tons per year, are generated along the Texas coast. The significance of impacts (by location and environmental media) are summarized in Table 1.

In general, the use of lignite by industry, whether by MBG or direct firing, will be subject to the same federal and state environmental regulatory programs. From a technological standpoint, the greatest area of regulatory uncertainty is in the development of MBG pollution control guidance documents (PCGDs) and regulations by the U.S. Environmental Protection Agency. Current plans call for the PCGD providing control technology guidance for Lurgi MBG facilities to be issued in 1983 and supporting regulations in 1985. Uncertainty in the content and actual timing of these regulatory documents complicates private synthetic fuel project planning. From a siting standpoint, the socioeconomic impacts of gasification facility construction in Central Texas are expected to be highly significant, but are regulated only in the NEPA environmental review processes. The absence of local

TABLE 1 COMPARISON OF IMPACTS FROM MBG AND DF SCENARIOS*

	Mining	Gasifi- cation	Transpor- tation	Utili- zation	Overall
<u>Air Quality</u>					
MBG Scenario	2	2	0	2	2
DF Scenario	1	0	1	3	3
<u>Water Quality</u>					
MBG Scenario	1	2	0	0	2
DF Scenario	1	0	0	1	1
<u>Water Use</u>					
MBG Scenario	2	2	0	0	2
DF Scenario	2	0	0	2	2
<u>Solid Waste</u>					
MBG Scenario	1	2	0	0	2
DF Scenario	1	0	0	2	2
<u>Land Use</u>					
MBG Scenario	2	2	1	0	2
DF Scenario	2	0	0	2	2
<u>Ecology</u>					
MBG Scenario	2	1	1	0	2
DF Scenario	2	0	1	1	2
<u>Socioeconomic</u>					
MBG Scenario	2	3	0	0	3
DF Scenario	2	0	1	1	2

* 0-negligible or no impacts
 1-minor impacts
 2-moderate impacts
 3-major impacts

MBG - Medium Btu Gas
 DF - Direct Firing

government regulatory and financial assistance programs to mitigate locally adverse impacts from major industrial growth are expected to be of major importance during construction of the MBG facility. Table 2 presents a prioritized listing of significant regulatory gaps and constraints for both scenarios.

TABLE 2. COMPARISON OF SIGNIFICANT REGULATORY CONSTRAINTS*

MBG Scenario	DF Scenario
1. Lack of county-wide land use controls (mining/gasification)	1. PSD and nonattainment regulations (utilization)
2. NEPA requirements (mining/gasification)	2. Solid waste regulations (utilization)
3. Lack of BACT/BAT/NSPS emission and effluent limitations guidelines (gasification)	3. NEPA requirements (mining/utilization)
4. Water quality regulations (mining/gasification)	4. Water quality regulations (mining/utilization)
5. Solid waste regulations (gasification)	5. Water use regulations (mining/utilization)
6. PSD and nonattainment regulations (utilization)	6. Lack of BACT/BAT/NSPS emission and effluent limitations guidelines (utilization)
7. Water use regulations (mining)	
8. Ambiguous jurisdiction of TRC over MBG pipelines (transportation)	

* In order of relative significance.



TABLE OF CONTENTS

	<u>Page</u>
EXECUTIVE SUMMARY	i
LIST OF FIGURES	xxv
LIST OF TABLES	xxix
 1.0 INTRODUCTION	 1
1.1 Background	1
1.2 Report Overview and Scope	3
1.3 Report Limitations	6
 2.0 TECHNOLOGY CHARACTERIZATION	 9
2.1 Overview	9
2.2 Medium Btu Gasification Scenario	11
2.2.1 MBG Mining Module	13
2.2.1.1 Technology Description	13
2.2.1.2 Environmental Issues	19
2.2.2 Medium Btu Gasification Module	23
2.2.2.1 Technology Description	23
2.2.2.2 Environmental Issues	36
2.2.3 MBG Transportation Module	46
2.2.3.1 Technology Description	46
2.2.3.2 Environmental Issues	47
2.2.4 MBG Utilization Module	49
2.2.4.1 Technology Description	49
2.2.4.2 Environmental Issues	52
2.3 Direct Firing Scenario	54
2.3.1 Direct Use Mining Module	55
2.3.1.1 Technology Description	55
2.3.1.2 Environmental Issues	56



TABLE OF CONTENTS (Continued)

2.3.2	Direct Use Transportation Module	57
2.3.2.1	Technology Description	57
2.3.2.2	Environmental Issues	61
2.3.3	Direct Firing Module	62
2.3.3.1	Technology Description	62
2.3.3.2	Environmental Issues	66
2.4	Comparison of Resource Requirements and Environmental Residuals	72
2.4.1	Lignite Requirements	72
2.4.2	Water Requirements	72
2.4.3	Air Emissions	75
2.4.4	Wastewater Discharges	76
2.4.5	Solid Waste	76
3.0	ENVIRONMENTAL ANALYSIS	79
3.1	Overview	79
3.2	Existing Environmental Baseline	80
3.2.1	Central Texas	80
3.2.1.1	Air Quality	82
3.2.1.2	Geology, Topography, and Soils	90
3.2.1.3	Surface Water Hydrology	93
3.2.1.4	Ground Water Hydrology	100
3.2.1.5	Ecology	101
3.2.1.6	Socioeconomics	104
3.2.2	Coastal Texas	106
3.2.2.1	Air Quality	108
3.2.2.2	Geology, Topography, and Soils	113
3.2.2.3	Surface Water Hydrology	114
3.2.2.4	Ground Water Hydrology	116
3.2.2.5	Ecology	117

TABLE OF CONTENTS (Continued)

	3.2.2.6 Socioeconomics	121
3.3	Major Gasification Impacts	123
3.3.1	Central Texas	123
3.3.1.1	Air Impacts	123
3.3.1.2	Geology, Topography, and Soils	127
3.3.1.3	Surface Water Hydrology	130
3.3.1.4	Ground Water Hydrology	132
3.3.1.5	Ecology	137
3.3.1.6	Socioeconomics	140
3.3.2	Transportation Corridor	148
3.3.3	Coastal Texas	149
3.3.3.1	Air Impacts	149
3.3.3.2	Other Impact Areas	151
3.4	Major Direct Firing Impacts	151
3.4.1	Central Texas	151
3.4.1.1	Air Impacts	151
3.4.1.2	Geology, Topography, and Soils	153
3.4.1.3	Surface Water Hydrology	153
3.4.1.4	Ground Water Hydrology	153
3.4.1.5	Ecology	154
3.4.1.6	Socioeconomics	154
3.4.2	Transportation Corridor	154
3.4.3	Coastal Texas	157
3.4.3.1	Air Impacts	157
3.4.3.2	Geology, Topography, and Soils	159
3.4.3.3	Surface Water Hydrology	159
3.4.3.4	Ground Water Hydrology	159
3.4.3.5	Ecology	161
3.4.3.6	Socioeconomics	161



TABLE OF CONTENTS (Continued)

3.5	Comparison of Impacts from MBG and DF	
	Scenarios	162
3.5.1	Air Quality	162
3.5.2	Water Quality	164
3.5.3	Water Use	165
3.5.4	Solid Waste	166
3.5.5	Land Use	166
3.5.6	Ecology	166
3.5.7	Socioeconomics	167
4.0	REGULATORY IDENTIFICATION	169
4.1	Overview	169
4.2	National Environmental Policy Act of 1969	171
4.2.1	Introduction	171
4.2.2	Criteria/Elements	172
4.2.3	Permit Process	176
4.2.4	Applicability	178
4.3	Land Use Controls	179
4.3.1	Introduction	179
4.3.2	Surface Mining and Reclamation	182
	4.3.2.1 Background	182
	4.3.2.2 TSCMRA Performance Standards	
	Criteria	185
	4.3.2.3 Surface Mining Performance	187
	Standards	
	4.3.2.4 Procedural Requirements Under	188
	TSCMRA	
4.3.3	Transportation-Related Controls	190
	4.3.3.1 Background	190
	4.3.3.2 Railroad-Related Land Use	
	Controls	190

TABLE OF CONTENTS (Continued)

4.3.3.3	Pipeline-Related Land Use Controls	191
4.3.4	Controls Associated with New Industrial Facilities	198
4.3.4.1	Background	198
4.3.4.2	National Flood Insurance Program	199
4.3.4.3	The Coastal Zone Management Program	207
4.4	Water Quality Controls	216
4.4.1	Introduction	216
4.4.2	Federal Water Quality Programs	217
4.4.2.1	National Pollutant Discharge Elimination System	217
4.4.2.2	Underground Injection Control (UIC)	228
4.4.2.3	Ocean Dumping Permit	236
4.4.2.4	Oil Spill Approval	239
4.4.3	State Program -- Texas Waste Discharge Program	244
4.5	Water Use Controls	247
4.5.1	Introduction	247
4.5.2	Federal Programs	248
4.5.2.1	Corps of Engineers Authorizations	248
4.5.2.2	FNERDA Water Resources Availability Review	252
4.5.3	State Programs	254
4.5.3.1	TDWR Water Use Permit	254
4.5.3.2	TDWR Dam Construction Approval	256

TABLE OF CONTENTS (Continued)

4.5.3.3	TDWR Floodplain Reclamation Approval	257
4.5.3.4	TPWD Dredge and Fill Permit	258
4.5.3.5	Harris-Galveston Coastal Subsidence District Permit	259
4.6	Air Quality Controls	262
4.6.1	Introduction	262
4.6.2	Prevention of Significant Deterioration (PSD)	267
4.6.2.1	History	267
4.6.2.2	Area Classifications	268
4.6.2.3	Source Applicability	270
4.6.2.4	Permit Process	274
4.6.3	Nonattainment -- Emission Offset Interpretive Ruling	276
4.6.3.1	History	276
4.6.3.2	Source Applicability	279
4.6.3.3	Permit Process	280
4.6.4	Texas Air Control Board Permits	281
4.6.4.1	Background	281
4.6.4.2	Permit Requirements/Process	283
4.6.5	Applicability	284
4.7	Solid Waste Controls	287
4.7.1	Introduction	287
4.7.2	RCRA Requirements	290
4.7.2.1	Performance Standards	290
4.7.2.2	Permit Process	292
4.7.3	Texas Solid Waste Disposal Program	294
4.7.4	Applicability	297
4.8	Toxic Substance Control	300



TABLE OF CONTENTS (Continued)

4.8.1	Introduction	300
4.8.2	Performance Standards	301
4.8.3	Permit Process	302
4.8.4	Applicability	304
4.9	Protection of Fish and Wildlife and Protection of Cultural and Historical Resources	305
4.9.1	Introduction	305
4.9.2	Fish and Wildlife Resources	306
4.9.2.1	Fish and Wildlife Coordination Act	306
4.9.2.2	Endangered Species Act	306
4.9.2.3	Texas Parks and Wildlife Code	307
4.9.3	Cultural and Historical Resources	310
4.9.3.1	The Historic Sites Preservation Act	310
4.9.3.2	Patriotism and the Flag	311
4.9.3.3	Texas Antiquities Code	312
4.10	Noise Controls	314
4.10.1	Federal Programs	314
4.10.2	Performance Standards	315
4.10.3	Permit Process	315
4.10.4	Applicability	315
4.11	Summary	319
5.0	REGULATORY ANALYSIS	327
5.1	Introduction	327
5.2	Substantive Regulatory Constraints	328
5.2.1	National Environmental Policy Act Impacts	328

TABLE OF CONTENTS (Continued)

5.2.2	Air Quality Impacts	332
5.2.2.1	MBG Scenario	332
5.2.2.2	DF Scenario	336
5.2.3	Water Use Impacts	337
5.2.3.1	MBG Scenario	337
5.2.3.2	DF Scenario	339
5.2.4	Water Quality	340
5.2.4.1	MBG Scenario	340
5.2.4.2	DF Scenario	342
5.2.5	Solid Waste Impacts	342
5.2.5.1	MBG Scenario	342
5.2.5.2	DF Scenario	343
5.2.6	Land Use Impacts	344
5.2.6.1	MBG Scenario	344
5.2.6.2	DF Scenario	347
5.3	Regulatory Gaps, Conflicts, and Voids	348
5.3.1	Regulatory Gaps	348
5.3.1.1	Administrative Gaps	348
5.3.1.2	Standards/Criteria Gaps	350
5.3.1.3	Jurisdictional Gaps	353
5.3.2	Regulatory Conflicts	354
5.3.2.1	Federal/State Conflict	355
5.3.2.2	Interagency Conflict	356
5.3.3	Regulatory Voids	357
5.3.3.1	Powers of Counties	358
5.3.3.2	Powers of Municipalities	359
5.3.3.3	Comparison	361
5.4	Procedural Constraints	362
5.5	Conclusions	363

TABLE OF CONTENTS (Continued)

BIBLIOGRAPHY	367
APPENDIX A	373
APPENDIX B	387
APPENDIX C	393

LIST OF FIGURES

		<u>Page</u>
2.1-1.	Alternative Lignite Utilization Scenarios	10
2.2-1.	Surface Mining Activities	14
2.2-2.	Surface Mining Process Flow Diagram	16
2.2-3.	Coal Conversion Possibilities	24
2.2-4.	Simplified Process Flow Diagram for a Lurgi Medium Btu Gasification Plant	27
2.2-5.	Process Zones and Chemical Reactions in the Lurgi Gasification Process	31
2.2-6.	Basic Process of a Gas-Fired Industrial Boiler . .	51
2.3-1.	Coal Unit Train Transportation System	59
2.3-2.	Direct Firing Process Flow Diagram	63
2.4-1.	Comparison of Resource Requirements and Residuals for the MBG and DF Scenarios	74
3.2-1.	Central Texas Region	81
3.2-2.	Hypothetical Lignite Development Site	83
3.2-3.	Wind Rose at the Central Texas Site	84
3.2-4.	Year 2000 Critical River Basin Segments	99
3.2-5.	Gulf Coast Study Area	107
3.2-6.	Wind Rose at Hobby Airport, Houston, Texas	109
3.2-7.	Estimated Annualized Impact of Existing Permits on the SO ₂ PSD Increment (µg/m ³)	112
4.2-1.	Sequence of Events: NEPA EIS Process	177
4.4-1.	Basic EPA NPDES Permit Process	226
4.8-1.	Flow Chart of TSCA Decision Paths	303
4.9-1.	Procedures for Parks and Wildlife Dredging Permits	308

LIST OF FIGURES (Continued)

4.10-1.	Expected Human Resources to Various Day-Night Noise Levels	317
4.11-1.	Relative Significance and Timing of Federal Licenses, Permits and Compliances Required from Planning Through Operation of a Typical Synthetic Fuels Project	324
4.11-2.	Relative Significance and Timing of State, County, and City Licenses, Permits and Compliances for a Typical Synthetic Fuels Project	325



LIST OF TABLES

		<u>Page</u>
1.1-1.	U.S. Industrial Locations Exceeding 150 Billion Btu per Day of Fuel Use (1973)	2
2.1-1.	Proximate Analysis of Design Lignite	11
2.2-1.	Fugitive Dust Emissions from a 6.0 MPTY Surface Mine	20
2.2-2.	Office of Surface Mining Effluent Limitations (Values in milligrams per liter (mg/l) except for pH)	22
2.2-3.	Material Balances for 150 Billion Btu per Day Lurgi Gasification Plant	28
2.2-4.	Cleaned Lurgi Product Gas Composition	33
2.2-5.	Composition of Stretford Unit Blowdown Water	34
2.2-6.	Composition of Untreated Lurgi Gas Liquor	35
2.2-7.	Composition of Treated Lurgi Gas Liquor Wastewater	36
2.2-8.	Stretford Unit Tail Gas Incinerator Emissions for 150 Billion Btu per Day Plant	38
2.2-9.	Coal-fired Boiler Air Emissions Factors and Air Emissions	39
2.2-10.	Comparison of Process Wastewaters	41
2.2-11.	Untreated Process Condensate: (Organic) Pollutants and Other Potentially Harmful Compounds	43
2.2-12.	Best Available Technology Effluent Limitations Guidelines for By-Product Coke Making Biological Treatment Systems	44
2.2-13.	Solid Waste From Lurgi Gasification Plant	45



LIST OF TABLES (Continued)

2.2-14.	Product Gas Specifications	48
2.2-15.	MBG Combustion Characteristics	50
2.2-16.	Steam Generation Emissions for 150 MMBtu/D of MBG New Source Performance Standards and Estimated Total Emissions	53
2.3-1.	Fugitive Emissions from a 4.2 MTPY Surface Mine .	57
2.3-2.	Diesel Locomotive Emissions	62
2.3-3.	EPA Emission Factors, New Source Performance Standards and Estimated Total Emissions from the Combustion of Lignite	67
2.3-4.	Discharge Limits on Bottom Ash Transport Water for Steam-Electric Plants	69
2.3-5.	Characteristics of Ash Pond Overflows with Total Suspended Solids Concentrations Less Than 30 mg/l .	70
2.3-6.	Solid Waste From Lignite-Fired Boiler	71
2.4-1.	Comparison of Residuals and Resource Requirements and Residuals for the MBG and DF Scenarios	73
3.2-1.	National Ambient Air Quality Standards	85
3.2-2.	PSD Class II Standards	86
3.2-3.	Averaged Monthly and Annual Air Quality Levels at Central Texas Site (July 1976 through June 1977) (Units: Concentrations-Micrograms per Cubic Meter; Wind Speed-Miles per Hour; Wind Direction- Degrees Clockwise from North)	87
3.2-4.	Five Highest Concentrations of TSP and SO ₂ at Central Texas Site	88
3.2-5.	Water Quality Standards, Segment 1242 of the Brazos River	97



LIST OF TABLES (Continued)

3.2-6.	1979 Ambient Air Quality Summary for CAMS No. 1 and No. 10 ($\mu\text{g}/\text{m}^3$)	111
3.3-1.	Fugitive Emissions from a 6.0 MTPY Surface Mine .	124
3.3-2.	Estimated Emissions from the Lignite Gasification Plant	126
3.3-3.	Labor Requirements for Gasification Plant	141
3.4-1.	Fugitive Emissions from a 4.2 MTPY Surface Mine .	152
3.4-2.	Labor Requirements for the Direct Use Mine	155
3.5-1.	Comparison of Impacts from MBG and DF Scenarios .	163
4.3-1.	Land Use Controls	180
4.3-2.	Surface Mining Controls: Corresponding Federal and State of Texas Statutes and Regulations	183
4.3-3.	Land Use Regulations Under Alternative I	192
4.3-4.	Minimum Land Use Controls Under the NFIP	202
4.3-5.	Participating Entities--National Flood Insurance Program State of Texas	206
4.3-6.	Uses and Activities Subject to Management	212
4.4-1.	Factors Relevant to NPDES Effluent Limitations Guidelines	220
4.4-2.	BAT Effluent Guidelines Development Schedule	222
4.4-3.	Classification of Injection Wells Under State UIC Programs	232
4.6-1.	Emission Standards Under the Clean Air Act, as Amended	264
4.6-2.	Ambient Standards and Maximum Allowable PSD Increments	269
4.6-3.	Major Source Types in PSD Regulations	272
4.6-4.	Facility Categories for which Fugitive Emissions Must be Calculated in Potential Emissions	275



LIST OF TABLES (Continued)

4.6-5.	Basic Requirements of PSD BACT Determination . . .	277
4.7-1.	RCRA Application Process	293
4.10-1.	Summary of Noise Levels Identified as Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety	316
4.11-1.	Permits/Approvals Required for MBG and DF Scenarios	320
5.2-1.	Key Environmental Issues Raised by MBG and DF Scenarios	329
5.3-1.	Municipal Zoning and Building Authority	360
5.3-2.	Extraterritorial Jurisdiction in Texas	361
5.5-1.	Comparison of Significant Regulatory Constraints for MBG and DF Scenarios	364



1.0 INTRODUCTION

1.1 Background

The growth of Texas industry over the past third of a century has been significantly dependent upon an abundant and relatively inexpensive supply of natural gas. Natural gas has provided energy for firing boilers and heating furnances and feedstocks for producing a wide variety of petrochemical products. In order to have access to ocean transportation and because of the availability of labor and other infrastructural needs, much of this industrial growth occurred along the Gulf Coast between Corpus Christi and Beaumont. As shown in Table 1.1-1, of the eleven major centers of industrial energy use in the U.S., five occur in this region.

As a replacement for natural gas as an industrial boiler fuel, significant interest has been shown in the potential use of Texas lignite. Based on current resource estimates and economic mining to a depth of 150 feet, Texas lignite reserves total approximately 144 quadrillion Btu--an amount of energy exceeding that of the state's currently known and economically recoverable reserves of oil, natural gas and natural gas liquids combined. Although significant commitments of this lignite reserve have already been made by the state's electric utility industry, substantial quantities of lignite could be committed to use in the industrial sector over the next three decades. Extensive deep basin lignite resources also could be a potential major energy source in the future.

TABLE 1.1-1. U.S. INDUSTRIAL LOCATIONS EXCEEDING 150 BILLION BTU PER DAY OF FUEL USE (1973)¹

Location	Fuel Use ²
TEXAS--SE of Beaumont Along Sabine River and Lake	517
TEXAS--10 Miles E of Houston	488
TEXAS--60 Miles S of Houston	259
INDIANA--SE Edge of Chicago	248
LOUISIANA--10 Miles S of Baton Rouge	237
TEXAS--40 Miles SE of Houston	226
LOUISIANA--25 Miles W of New Orleans	167
LOUISIANA--SW Louisiana on Calcasieu River	162
PENNSYLVANIA--Philadelphia River Front	155
TEXAS--10 Miles E of Corpus Christi	152
LOUISIANA--6 Miles E of New Orleans	151

¹Does not include fuel use by electric utilities.

²Billion Btu per day.

Source: Barnes, 1976.

The two options for this substitution of lignite for natural gas to occur are through the direct use of lignite to produce process steam in industrial boilers and the conversion of lignite to a synthetic fuel which could be used as an industrial fuel or feedstock. Given the commercial status of synthetic fuel technologies, proximity of the lignite resource to the centers of industrial demand discussed above, and the heavy dependence of these industries on a gaseous fuel, it appears likely that the predominant synthetic fuel produced from Texas lignite will be medium Btu gas (MBG) and that the most likely technology to be used will be the Lurgi dry-bottom process. Both Exxon's East Texas Synthetics Project near

Troup and the U.S. Department of Energy feasibility study award to Transco, Inc. for a synthetic fuels project in Robertson County are based on production of MBG via the Lurgi process.

Because of the absence of commercial application of this technology in the U.S.¹, uncertainty exists with regard to its economic and environmental impacts and to the impact of public policy and regulations on its commercialization in this country. The Energy Security Act (P.L. 96-924) passed by Congress in 1980 recognizes this uncertainty and provides federal assistance for the development of a synthetic fuels industry in the U.S. In directing the allocation of funding under Title I of the ESA, Congress called for priority consideration to be given projects located in those states which supported such development through a statement of intent to expedite regulatory licensing and related state government activities.

1.2 Report Overview and Scope

The primary objective of the analysis presented in this report is to systematically evaluate the comparative environmental impacts and regulatory requirements associated with the use of lignite as an industrial fuel. Because of the responsibility of state government to protect environmental quality while not imposing unnecessary regulatory burdens on the private sector, this report focuses on the:

¹The Lurgi process was originally developed in Germany prior to World War II and has been used elsewhere in the world since then, most notably in South Africa. Much of the environmental control technology expected to be required on this process in the U.S. has not been required on these foreign units and has therefore not been commercially demonstrated.

- Identification of government environmental policies and regulations of relevance to the use of lignite and lignite-derived MBG, and
- Evaluation of the comparative significance of these policies and regulations on the alternatives of direct lignite use versus production and use of MBG.

In so doing, the report defines two scenarios (or alternatives). The first scenario is based on the conversion of lignite to MBG at a mine-mouth gasification facility located in Central Texas and pipelining the gas to industrial consumers along the Gulf Coast for use in existing boilers. The second scenario assumes the shipment of lignite by railroad to the same industrial consumers for use in new boilers constructed to burn lignite. In both scenarios, the amount of energy produced and transported is established so as to ultimately yield equal quantities of useful energy to the industrial consumer.

The report is divided into four major chapters reviewing the technology, environmental implications, existing regulatory framework, and implications of regulatory constraints and uncertainties on the two scenarios. Each of the chapters is briefly discussed below. Taken as a whole, the report provides a rough indication of the potential adequacy and inconsistencies in existing environmental regulatory programs impacting future industrial lignite use in Texas.

Chapter 2 evaluates the technology requirements, resource commitments and environmental residuals associated with the two scenarios. The basis for comparison is net energy demand by industry of 150 billion Btu per day. While a broad

range of factors are discussed, primary emphasis is on comparison of the following parameters: lignite requirements, water requirements, air emissions, wastewater discharges, and solid waste. This information is then used as the basis for the subsequent analysis of environmental and regulatory considerations evaluated in Chapters 3, 4, and 5. An important consideration in this analysis is the selection of the Lurgi process. This decision was not only based on its greater likelihood of use as discussed in Section 1.1, but also because Lurgi entails a broader range of potential environmental impacts and issues than most of the other major processes expected to be commercially available during the next decade. To this extent, it is important to remember that this analysis applies to the technologies described in Chapter 2 and may not be directly applicable to other MBG processes.

Given the resource requirements and environmental residuals developed in Chapter 2, Chapter 3 estimates the comparative environmental impacts resulting from locating these technologies at hypothetical sites in the Central Texas and Galveston Bay areas. While these sites were created specifically for this study and are not actual sites, they are intended to be representative of the general environmental characteristics of the region they have been designed to represent. Whereas Chapter 2 estimated the quantity of resources consumed and environmental residuals associated with a specific set of technologies, Chapter 3 translates residuals into environmental impacts and attempts to identify physical constraints on technology emplacement. In so doing, Chapter 3 identifies site-related issues of importance in Chapters 4 and 5. Areas of impact discussed in Chapter 3 are air quality, water quality, water use, solid waste, land use, ecology and socioeconomics.

Chapter 4 catalogs local, state and federal environmental requirements impacting the two scenarios and defines the nature and extent of potential regulatory impacts associated with each scenario. This work was primarily accomplished through analysis of relevant statutes and regulations. Secondary sources and discussions with regulatory agency personnel were used as necessary to identify agency interpretation of rules and program status. The chapter discusses the following major areas: overall environmental planning, land use, water quality, water use, air quality, solid waste, ecological resources, cultural and historical resources, and noise.

The impact of key state and federal regulatory requirements on the two scenarios is analyzed in Chapter 5. Because of the greater regulatory uncertainty associated with lignite gasification, primary emphasis is placed on this scenario. Consistent with the report's overall objective of comparing the two scenarios, Chapter 5 stresses those areas of substantive and procedural constraints and uncertainties which are either peculiar to or disproportionately impact one scenario more than the other.

1.3 Report Limitations

This report presents information which is intended to assist in better understanding the implications of industrial lignite use and synthetic fuels development in Texas. To be properly used in the context of overall technology assessment and public policymaking, it is important to understand not only what is contained in this report, but also to recognize its limitations. The following paragraphs discuss these limitations in the report's findings.

This report is confined to analyzing the environmental characteristics of the technologies described herein. No explicit consideration has been given to alternative technologies, process and transportation economics, resource availability and land ownership, public and occupational health and safety (other than those implicit in the regulations studied), and other non-environmental areas which will be of major importance in the development of specific projects.

While this report was based on the evaluation of hypothetical sites located in Central Texas and the area surrounding Galveston Bay, it should not be inferred that these areas are necessarily the most likely or best regions for development. Furthermore, the analysis conducted in conjunction with these hypothetical sites should not be interpreted as being directly transferable to specific sites or projects located in these or other regions.

Directly following from the above, this analysis does not substitute for the National Environmental Policy Act (NEPA) requirements associated with the development of a specific project and site. Similarly, the regulatory analysis contained in Chapters 4 and 5 is based on the generic requirements of existing environmental laws and may differ in detail for specific projects.

The primary focus of this report is on the impacts associated with individual projects. While regional issues, such as the availability of surface water and socioeconomic infrastructure in Central Texas, have been discussed as to the extent that they will influence the development of individual projects, assessment of all regional or cumulative impacts from

development of multiple projects has not been attempted. For a discussion of regional environmental impacts and issues resulting from the cumulative development of Texas lignite, see An Integrated Assessment of Texas Lignite Development.

The final limitation noted with regard to the study pertains to the data upon which the analysis was conducted. With regard to synthetic fuels technologies in particular, little field data exists on the actual emissions from these processes. While the Lurgi process is in use elsewhere in the world and some data has been collected on the environmental emissions from those plants, the level of environmental control technology (ECT) employed on those units is less substantial than that postulated in this report and likely to be required by environmental regulatory agencies in the U.S. Many of the estimates of emissions presented in this report are based on engineering judgements made by individuals and organizations involved in the development, testing, and regulation of these systems. Although most of the numbers presented in this report are given as a single value, current understanding and uncertainty with regard to many of the processes is such that in some instances, the given number is an order-of-magnitude estimate within a range of possible numbers. Except where otherwise noted, the numbers presented in the report are based on analyses and reports by Radian personnel.

2.0 TECHNOLOGY CHARACTERIZATION

2.1 Overview

The objective of this chapter is to evaluate the technology requirements, resource commitments, and environmental residuals associated with the provision of 150 billion Btu per day of energy to industrial boilers located in the coastal zone of Texas. This energy is supplied either by the conversion of lignite to medium Btu gas (MBG) at a mine-mouth gasification facility, pipelining to the coast, and using existing gas-fired boilers or by the shipment of lignite by rail to coastal industries for direct firing in new industrial boilers designed to burn lignite. These alternatives are schematically shown in Figure 2.1-1. The analysis conducted in Chapter 2 is not specific to a single site, but is generic for the selected technologies. This information is then used as the basis for the subsequent analyses of environmental and regulatory considerations associated with industrial lignite use in Chapters 3, 4, and 5.

Section 2.2 of this chapter analyzes the medium Btu gasification alternative (or scenario). Section 2.3 presents the analysis of the direct firing (DF) scenario. Section 2.4 compares the resource requirements and environmental loadings of the previous two sections as a function of both magnitude and location of occurrence. The emphasis throughout the chapter is on developing a consistent analysis based on the use of commercially available technology and existing environmental standards. No effort is made to investigate the potential for substantial improvements in energy efficiency or environmental quality as a result of the introduction of advanced technology or more stringent environmental standards. Where existing standards do

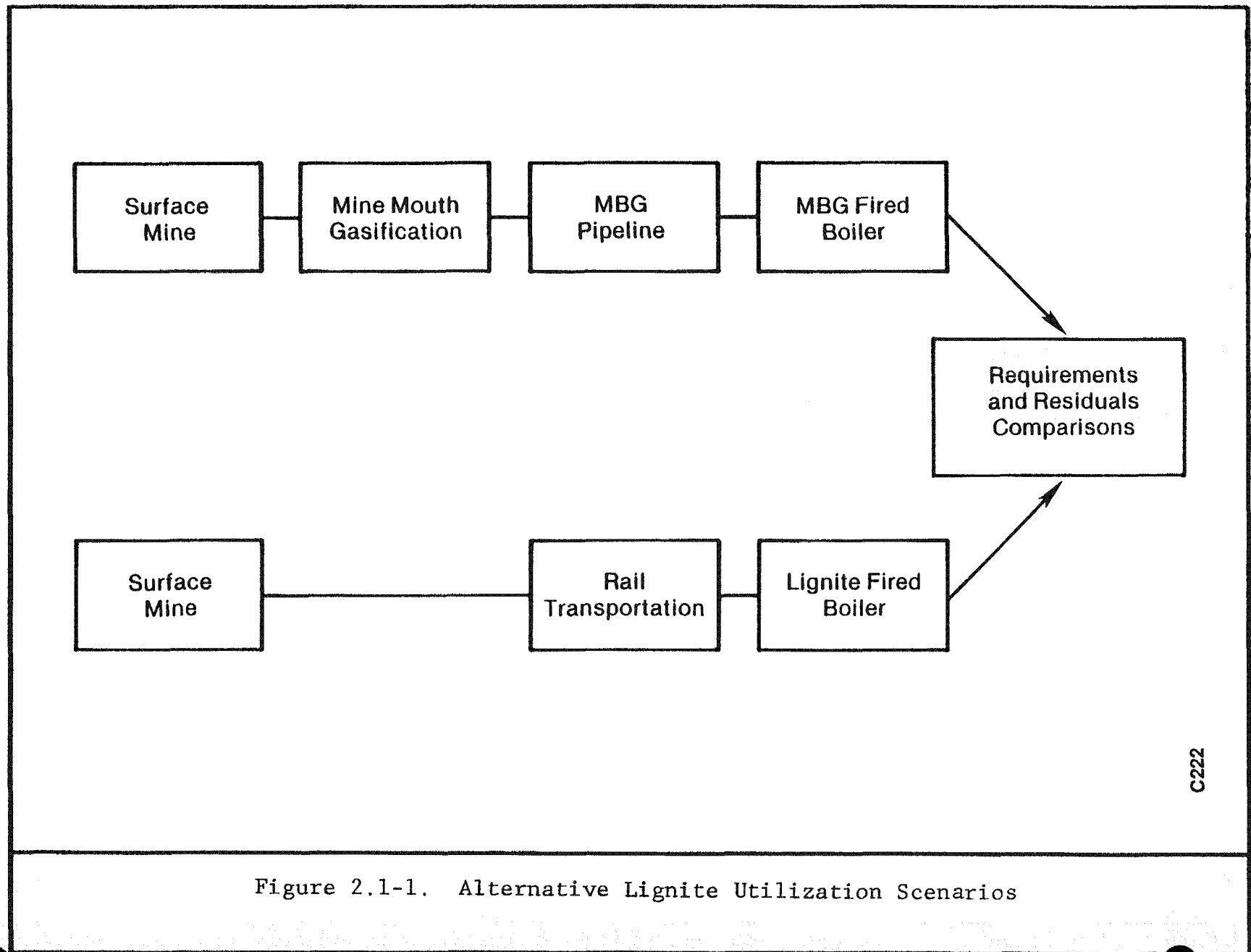


Figure 2.1-1. Alternative Lignite Utilization Scenarios

not currently exist (such as with the effluents from medium Btu gasification), requirements are set based on analogy with similar industrial processes. Informational resources and data regarding the selected technologies were taken from recently published literature and other readily available sources.

The lignite used in both of the scenarios is representative of the Wilcox Group in Texas. The design analysis is given in Table 2.1-1. In instances where climate, terrain, or other site specific considerations are critical to the analysis, conditions typical to those found in the watershed of the Brazos River of Central Texas are assumed.

TABLE 2.1-1. PROXIMATE ANALYSIS OF DESIGN LIGNITE

Parameter	Weight % (as received)
Fixed Carbon	23.5
Volatile Matter	29.0
Ash	12.5
Moisture	35.0
Sulfur	1.1
Heating Value (Btu/lb)	6,500

2.2 Medium Btu Gasification Scenario

The medium Btu gasification scenario (hereafter simply referred to as the MBG scenario) is composed of the four primary components shown in the top half of Figure 2.1-1. These components are:

- a mining module consisting of a 6 million ton per year surface mine,
- a gasification module consisting of a 150 billion Btu per day gasification facility,
- a pipeline module consisting of a 42 inch diameter pipeline for transporting MBG to coastal industries, and
- a utilization module consisting of existing industrial boilers designed to burn natural gas.

Each module is divided into two sections. The first section describes the technology(ies) selected including environmental controls, the general principles of process operation, and overviews the resource requirements and environmental residuals of the technology. The second section identifies the environmental issues stemming from the technology and completes the quantification of environmental loadings discussed in the first section.

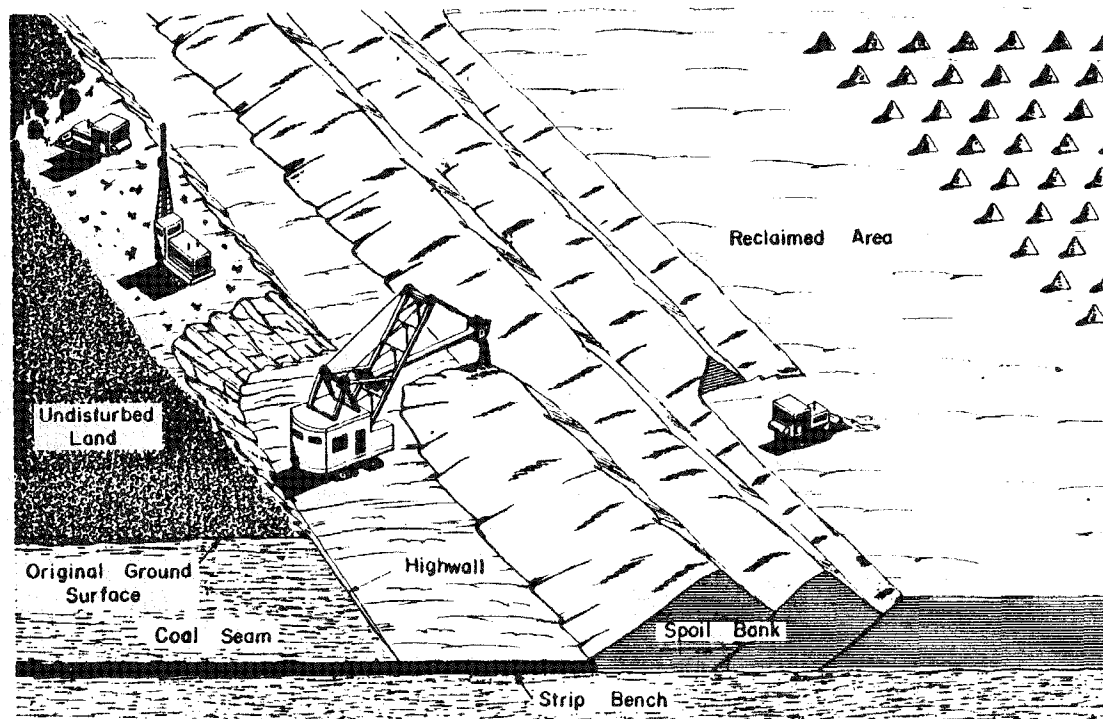
2.2.1 MBG Mining Module

2.2.1.1 Technology Description

This section describes the technology of surface lignite mining, including recovery of the lignite and control of associated pollutant emissions. At 6,500 Btu per pound of lignite, a 6.0 million ton per year mine would be required to feed a mine mouth lignite gasification plant producing 150×10^9 Btu/day of medium Btu gas. Technologies associated with this size mine are discussed.

Lignite is found in Texas in the Gulf Coast Plain from the Rio Grande to the Red and Sabine Rivers as near-surface and deep-basin deposits. Through an examination of known lignite deposits and their geological contexts, the Texas Bureau of Economic Geology¹ estimates that a total of 23.4 billion tons of lignite with a minimum seam thickness of three feet is located within 200 feet of the surface. Estimated reserves (that portion of the resource base which is well defined and recoverable under current economic conditions) are 11.1 billion tons. Typical seam thicknesses currently being mined range from six to fifteen feet.

Lignite is presently mined by area stripping. In flat to gently rolling terrain where lignite occupies a wide continuous area, overburden is removed in a series of rows. Overburden from the first row is piled next to the pit away from the direction mining will take, and the exposed lignite is removed. Subsequent cuts are made parallel to the first and the overburden is deposited in the immediate preceding pit (Figure 2.2-1).



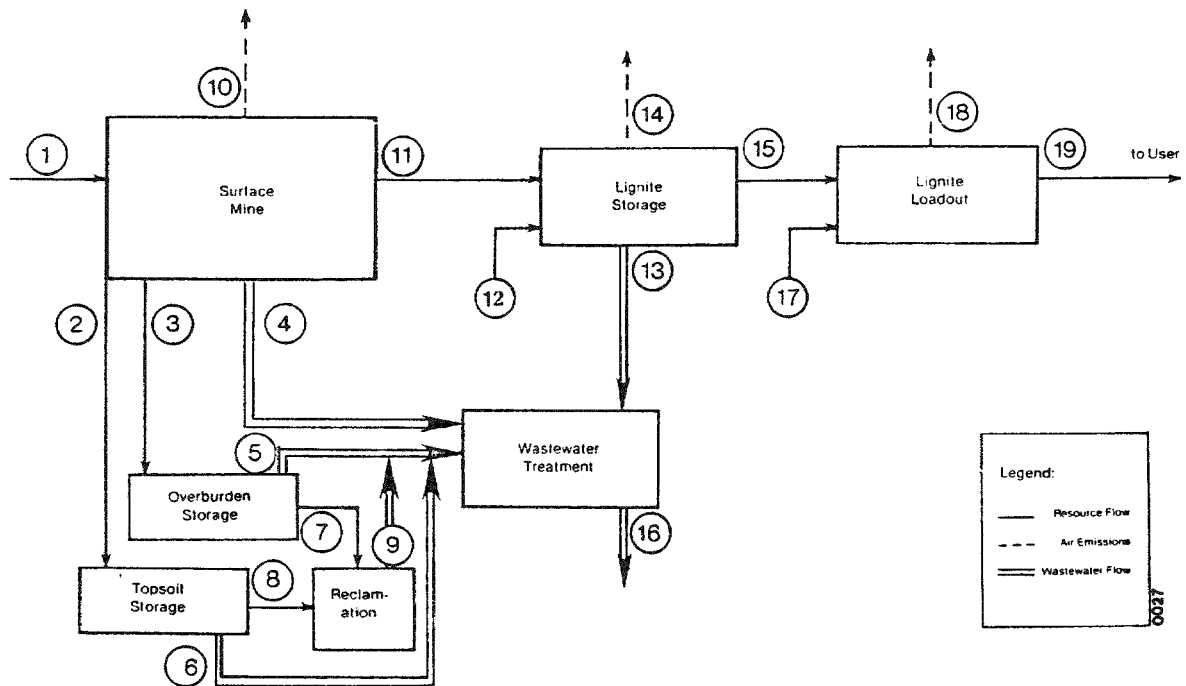
Source: USEPA, 1973

Figure 2.2-1. Surface Mining Activities

Modern earth-moving equipment and the availability of large lignite reserves below shallow, unconsolidated overburden make surface mining more economical than underground mining. Large draglines with buckets ranging in size up to 200 cubic yards and able to dig to a depth of 200 feet remove the overburden. Eighty-five percent of the lignite is typically recovered. Because deposits in Texas dip coastward at an average of about two degrees, the strippable near-surface deposits are generally confined to a narrow band (ten miles wide at most).

Assuming a seam thickness of seven to eight feet, a 6.0 million ton per year (mtpy) surface mine would require mining 375 acres per year. Approximately 1200 acres would be in some phase of mining or reclamation at any given time. Figure 2.2-2 presents a process diagram for a surface mine depicting resource and waste stream flows.

Devegetation is accomplished using clear-cutting techniques in woodlands and dozers and graders in rangeland. Chippers convert the woody material in the mining area to mulch that is applied to land then being reclaimed. After devegetation, typically a 70-cubic yard capacity dragline uncovers the (upper-most) lignite seam in a box cut, removing about 30 feet of overburden material. Separation of topsoil from overburden is required in cases where a mixture of the two is not satisfactory for regrowth of vegetation. The few remaining feet of strata immediately above the lignite seam are cleared by a bulldozer and this material is placed in the spoil valleys via truck transport. The lignite is excavated by a backhoe or front-end loader and transported by large trucks (up to 120 ton capacity) to storage, crushers or loadout hoppers. This extraction process typically creates a bench from which a bucket shovel



Key to Resources and Emissions Numbers

Process Flow Point	Description
1	Water for dust control
2	Topsoil to storage (when segregation is required)
3	Overburden removed from lignite seam
4	Mine area runoff
5	Overburden runoff
6	Topsoil runoff
7	Overburden returned for reclamation
8	Topsoil returned for reclamation
9	Runoff from partially reclaimed area
10	Fugitive dust emissions from overburden
11	Lignite to storage
12	Water for dust control
13	Runoff from lignite storage piles
14	Fugitive dust emissions from wind erosion
15	Lignite to loadout
16	Wastewater discharge to receiving stream or reuse
17	Water for dust control
18	Fugitive dust emissions from loadout
19	Lignite to transport system

Figure 2.2-2. Surface Mining Process Flow Diagram

works to uncover and mine lower lignite seams. The spoil material excavated by the shovel is loaded onto trucks and hauled to repose slopes of the box cut. As many as three benches (including the final pit floor) may be required, with a maximum mining depth of near 200 feet below the surface. Blasting for excavation or extraction is seldom required in Texas.

Material from the initial cut is stored and is vegetatively stabilized. Part of it is usually used for constructing haul road berms and visual barriers. The spoil piles are recontoured using dozers and graders; recontouring is designed to reestablish the drainage areas of the larger creeks in the area. No standing water is left in the reclaimed area and the final cut is completely backfilled.

Air pollutant emissions from surface mining activities are primarily particulate matter in the form of fugitive dust emissions. Wind erosion, construction activities, and mining activities (especially traffic on haul roads and extraction processes) are major causes of fugitive dust, and these sources are partially controllable. The technologies for control of these emissions are occasional oiling and frequent watering of haul roads, spray-watering of lignite storage piles, and dust collection systems (baghouses) at crushing plants. As lignite is loaded onto rail cars, a dust suppression system sprays water on the lignite to reduce fugitive dust at the loadout site as well as during transit.

The primary pollutant in water discharges associated with surface mining is suspended material in runoff from unreclaimed areas, or total suspended solids (TSS). The basic control technology for TSS is the sedimentation pond which, when

properly designed, is effective in reducing TSS to low levels. These structures are designed to retain the runoff from disturbed land resulting from the maximum 24-hour storm expected during a 10 year interval and to treat any water discharged so as to meet state and federal effluent limitations. Runoff from the active mine area is usually collected in a sump and pumped to the sedimentation pond. Surface waters which would normally flow through the mine area are diverted away from the mine area to avoid contamination and consequent treatment requirements. Runoff from coal storage areas also is directed into sedimentation ponds for treatment. Coal pile runoff is often characterized by low levels of pH and may require neutralization before discharging to meet wastewater permit requirements. Under dry weather conditions, a "no discharge" condition commonly prevails for sedimentation ponds since water from the ponds is being utilized for consumptive uses such as road watering and reclamation.

The water required for dust control at a 6.0 million ton per year mine is estimated to be about 1800 acre-feet per year (af/yr). This amount of water is required for watering haul roads, spraying lignite storage piles, and spraying lignite during loading activities.

Water requirements for reclamation vary greatly depending on rainfall and climate of the mine location. Reclamation and revegetation of an area requires as much as 2 af/yr per acre of land mined and reclaimed. Much of this 2 af/yr requirement could be provided by direct rainfall in the Central Texas portion of the lignite belt; therefore, there may be little or no supplementary water required for reclamation activities.

The water requirements for dust control and revegetation for a surface mine are satisfied to a large extent by the sedimentation pond water, although ground water is necessary occasionally during dry periods. Water supply for personnel consumptive use must meet drinking water standards and, therefore, must be either from a public water supply or from an acceptable quality aquifer.

2.2.1.2 Environmental Issues

This section discusses the environmental issues associated with a 6.0 million ton per year (mtpy) lignite surface mine in terms of resource requirements and pollutant emissions. The primary resource requirements are the lignite reserves, water resources, land resources, and the work force to operate the mine. Major pollutant emissions are sedimentation pond discharges and fugitive dust emissions.

Air Emissions

Air pollutants associated with surface mining are primarily fugitive dust emissions from haul roads, overburden removal, and lignite storage. These primary emissions have been estimated using the "EPA Region VIII Interim Policy Paper on the Air Quality Review of Surface Mining Operations." For a 6.0 mtpy mine the estimated fugitive emissions are given in Table 2.2-1.

Wastewater Discharges

The volume of water discharged from a 6.0 million ton per year mine is extremely variable and site specific. The water flowing into a sedimentation pond is derived from two primary

TABLE 2.2-1. FUGITIVE DUST EMISSIONS FROM
A 6.0 MPTY SURFACE MINE*

Process	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Controlled Emissions (tpy)
Haul Roads	1820-8500	85	270-1275
Overburden Removal	470-2775	-	470-2775
Stockpile Erosion	610	50	305

*The ranges reflect differences in mine depth, distances to storage facilities and other factors which will vary with time.

sources: First, rainfall runoff from the mine areas, storage areas, and partially reclaimed areas and, second, ground water seepage into the pit.

Runoff volumes are dependent on storm characteristics, soil types, topography and runoff control measures, among other things. High intensity or long duration storms tend to have a higher percentage of direct runoff than low intensity or short duration rainfall events. For example, in Central Texas, direct runoff from a 5.0 inch rainfall is predicted to be 1-3 inches (20-60 percent of rainfall) whereas direct runoff from a 1.0 inch rainfall is estimated to be from near zero to 0.2 inches (0-20 percent of rainfall). As an approximation for the total annual runoff from 1200 acres of disturbed and partially reclaimed area, an annual average of 35 inches of rainfall per year and 30% runoff is assumed, or about 10.5 inches of direct runoff per year. This runoff would result in 1050 af/yr of runoff directed to the sedimentation pond.

Pit seepage is also pumped to sedimentation ponds. The volume of seepage depends greatly on the depth and width of cuts and the characteristics of the aquifer at the mine. It has been estimated that 100 gallons per minute (160 acre feet per year) would be the approximate amount of seepage at a mine in the Calvert Bluff formation of Central Texas. This value would vary depending on the variables mentioned above.

The average total sedimentation pond inflow -- 1050 af/yr and 160 af/yr from runoff and pit seepage, respectively -- is less than the 1800 af/yr water requirement estimated previously for dust control and reclamation. Therefore, it is likely that a "no discharge" condition would prevail except during more intense rainfall events. In addition, water requirements not satisfied by sedimentation pond water would be supplied by ground water. Net ground-water requirements would average 590 af/yr (the total water requirements minus available pond water), but ground-water requirements could range from zero to 1800 af/yr depending on annual variation in rainfall.

Water quality standards established by the Office of Surface Mining (Environmental Protection Agency Effluent Guidelines are not yet final) for waters which are discharged from areas disturbed by mining activities are given in Table 2.2-2. Sedimentation ponds provide detention and settling of suspended solids, but specific treatment for pH, iron and manganese is usually not required. Acid mine drainage generally is not a significant problem in the Texas lignite belt because of the relatively low sulfur content of Texas lignite; therefore, the allowable pH range of 6.0-9.0 is usually maintained without specific treatment. Settling of suspended solids generally removes associated iron and manganese to acceptable limits prior to discharge.

TABLE 2.2-2. OFFICE OF SURFACE MINING EFFLUENT LIMITATIONS (Values in milligrams per liter (mg/l) except for pH)

Effluent Characteristics ¹	Maximum Allowable ²	Average of Daily Values for 30 Consecutive Discharge Days ²
Iron, total ³	7.0	3.5
Manganese, total ⁴	4.0	2.0
Total suspended solids	70.0	35.0
pH ⁵	Within range of 6.0 to 9.0	

¹To be determined according to collection and analytical procedures adopted by the Environmental Protection Agency's regulations for wastewater analyses (40 CFR 136).

²Based on representative sampling.

³Discharges of iron from new sources, as defined under 40 CFR Section 434.11(i), shall be limited to 6.0 mg/l (maximum allowable) and 3.0 mg/l (average of daily values for 30 consecutive discharge days).

⁴The manganese limitations shall not apply to untreated discharges which are alkaline as defined by the Environmental Protection Agency (40 CFR 434).

⁵Where the application of neutralization and sedimentation treatment technology results in inability to comply with the manganese limitations set forth above, the regulatory authority may allow the pH level in the discharge to exceed, to a small extent, the upper limit of 9.0 in order that the manganese limitations will be achieved.

Source: Texas Railroad Commission; 1980, Coal Mining Regulations.

Solid Waste

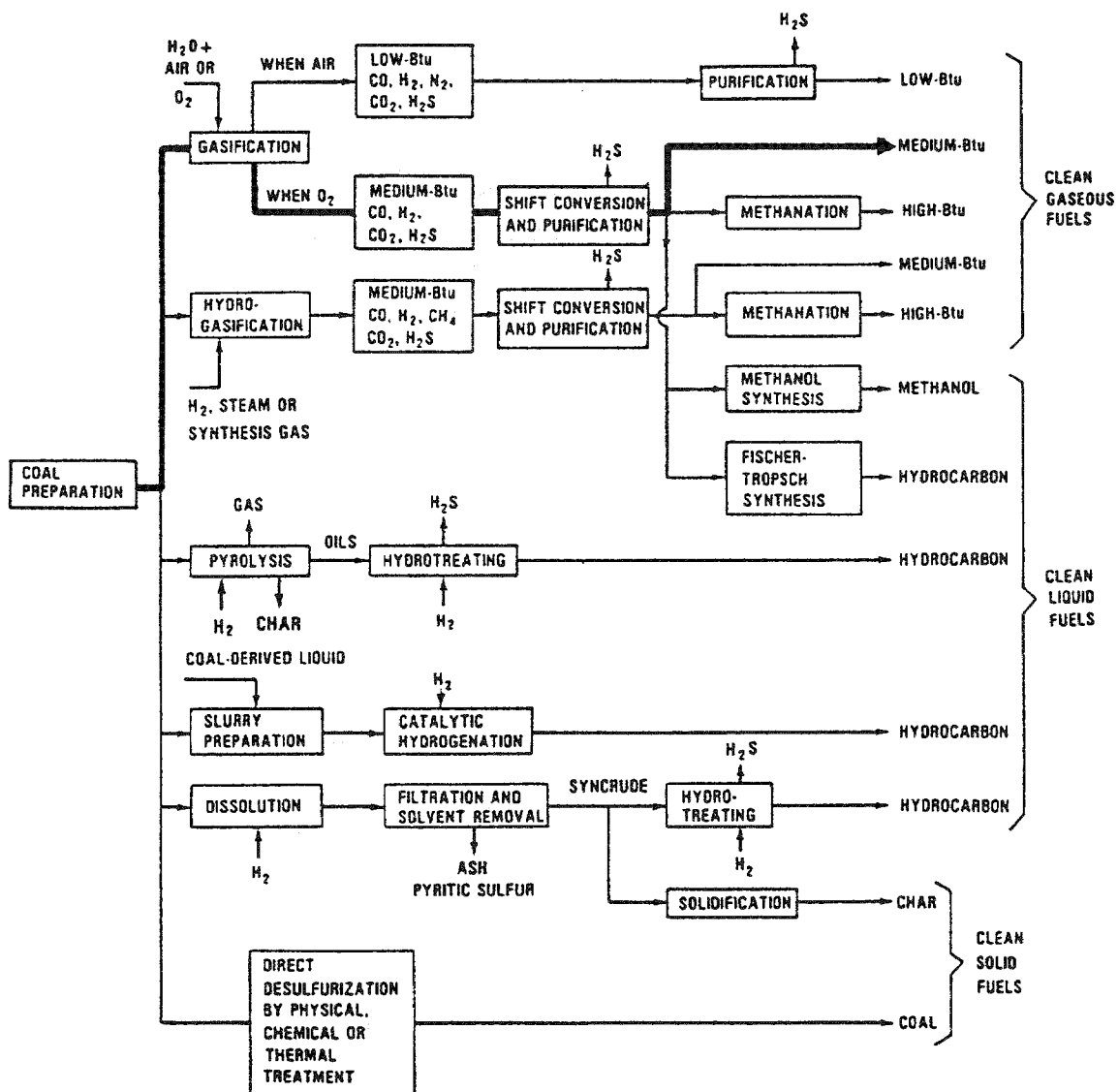
Although overburden is not normally considered a solid waste, the volume of overburden handled at a 6.0 mtpy surface mine would range from about 11,000 af/yr to near 75,000 af/yr. The range is primarily attributable to the depth of mining (from 30 feet to 200 feet). The amount of overburden handled will normally increase with time as the mining progressively increases in depth.

2.2.2 Medium Btu Gasification Module

2.2.2.1 Technology Description

Figure 2.2-3 is a generalized flow chart depicting alternative coal conversion possibilities. Essentially coal or lignite can be desulfurized, deashed, and further refined until a clean, easily transportable fuel results. Low Btu gas, a mixture of nitrogen (N_2), carbon dioxide (CO_2), carbon monoxide (CO) and hydrogen (H_2) gases, has a heating value of 100-200 Btu per cubic foot. High Btu gas, with a heating value of 900 to 1000 Btu per cubic foot, is composed mainly of methane (CH_4). Medium Btu gas is a mixture of CO, H_2 , CH_4 , and CO_2 with a heating value of 300-500 Btu per cubic foot. Gasification of coal to a medium Btu gas is also the first step in synthetic production of liquid hydrocarbons via indirect, Fischer-Tropsch liquefaction technology.

In simplest terms, medium Btu gasification (shown by heavy line in Figure 2.2-3) is the conversion of coal, water, and oxygen into the combustible gases of carbon monoxide (CO), hydrogen (H_2), and methane (CH_4). The sulfur in the coal is converted to hydrogen sulfide (H_2S), carbon disulfide (CS_2), and carbonyl sulfide (COS). Depending on the process,



Source: USERDA, 1976

Figure 2.2-3. Coal Conversion Possibilities

gasification can also produce some by-products which include phenols, naphtha, ammonia, tars, oils, and sulfur. The amount of each depends upon the plant size, gasification process and composition of the coal. The operating conditions of the gasifier will also have a significant effect upon the types of potential pollutants produced in the raw gas.

A key factor impacting the environmental residuals from coal gasification is the specific gasification process. Fixed-bed processes (such as the Lurgi gasifier) operate at relatively low temperatures (1800-2000°F), produce significant quantities of organic by-products, and will require extensive technology for control of gaseous, liquid, and solid waste streams. High-temperature, entrained-flow processes (such as the Koppers-Totzek and the Texaco gasifiers) do not produce significant amounts of organic liquid by-products and will not require as extensive controls for organic emissions. Control of inorganic pollutant streams will be required regardless of the type of gasification process used.

The dry-bottom Lurgi gasification process was selected for study in this program for two primary reasons. First, of the gasification technologies expected to be commercially available in the next ten years, Lurgi has more large-scale commercial experience, is the most thermally efficient at converting lignite to MBG, and is the most likely process to be used for gasification of Texas lignite. Second, because it produces both inorganic and organic pollutant streams, it encompasses a wider range of environmental impacts and related regulatory issues.

To produce 150 billion Btu of gas per day, a bank of 18 Lurgi gasification reactors, each with a 1,000 ton per day capacity, is required. Using the design lignite and an overall thermal efficiency for the plant of 69%, roughly 20,000 tons per day of lignite is required--14,000 tons to the gasifiers and up to 6,000 tons to produce the steam, electricity and oxygen, needed to run the plant. The operating factor for the plant is 82 percent. Acreage for the plant and related facilities are estimated at 500 acres. Including plant buffer zones, the total gasification project site will encompass approximately 1500 acres. Figure 2.2-4 presents a simplified process flow diagram for the gasification plant. Table 2.2-3 summarizes the overall material balances for the plant. The stream identification numbers of Figure 2.2-4 and Table 2.2-3 correspond to one another.

Utility requirements for the gasification plant are tabulated in the material balance including steam, water, oxygen, electricity and heat rejection (cooling tower). Estimates for water use by the Lurgi gasifiers and the plant are dependent upon the exact quality of the lignite. Water consumption figures that appear in the literature are typically expressed as ratios of water to coal or water to Btu of output gas in either units of mass to mass or mass to energy. These estimates range from 975 gpm to over 10,000 gpm for the 150 billion Btu/20,000 tons per day parameters in this analysis. Water estimates on a per ton or per Btu basis are difficult to apply since water use depends on many site dependent factors and since there are so few existing facilities of this type upon which to derive these figures. The 5,000 gpm used for the material balance (Table 2.2-3) has been extrapolated from a zero discharge scenario make-up water requirement of 3,000 gpm plus 1000 gpm for each

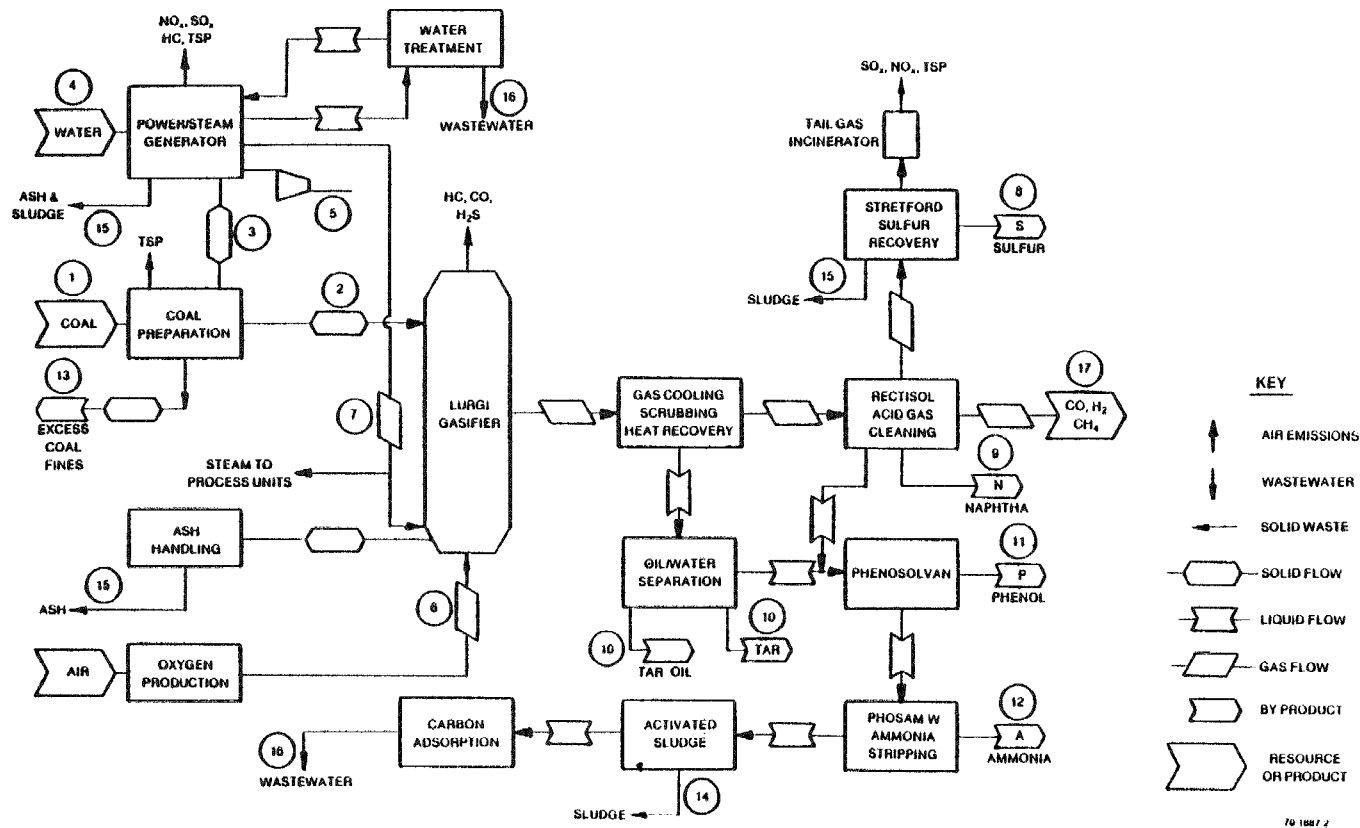


Figure 2.2-4. Simplified Process Flow Diagram For a Lurgi Medium Btu Gasification Plant

TABLE 2.2-3. MATERIAL BALANCES FOR 150 BILLION
BTU PER DAY LURGI GASIFICATION PLANT

IDENTIFICATION ¹ NO.	STEAM	QUANTITY
①	Coal to preparation - TPD	20,000
②	Coal to gasifier - TPD	14,000
③	Coal to boilers - TPD	5,100
④	Water - GPM	5,000
⑤	Electric generation - MW	40
⑥	Oxygen - TPD	2,800
⑦	Steam generation - TPD	22,000
⑧	Sulfur - TPD	130
⑨	Naphtha - BPD	1,000
⑩	Tar and tar oil - BPD	1,900
⑪	Phenol - BPD	420
⑫	Ammonia - TPD	80
⑬	Excess coal fines - TPD	900
⑭	Biological sludge - TPD	70
⑮	Ash and other sludges - TPD	3,585
⑯	Wastewater - GPM	2,000
⑰	Product gas	
	MMSCFD -	359
	HHV - Btu/SCF	418
	MMMBtu/SD -	150
<u>Heat Balance</u>	MMMBtu/SD	
	Input: Coal to plant	260
	Output: Product gas	150
	Fuel by-products	<u>30</u>
	Total	180
	Thermal Efficiency - %	69

¹ Keyed to Figure 2.2-4.

of the two organic and inorganic wastewater discharge streams. Raw water treatment includes clarification and reverse osmosis to meet boiler feed water requirements.

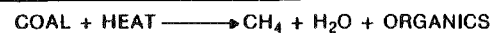
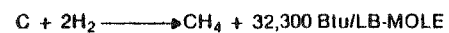
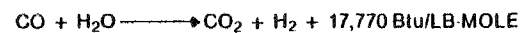
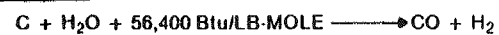
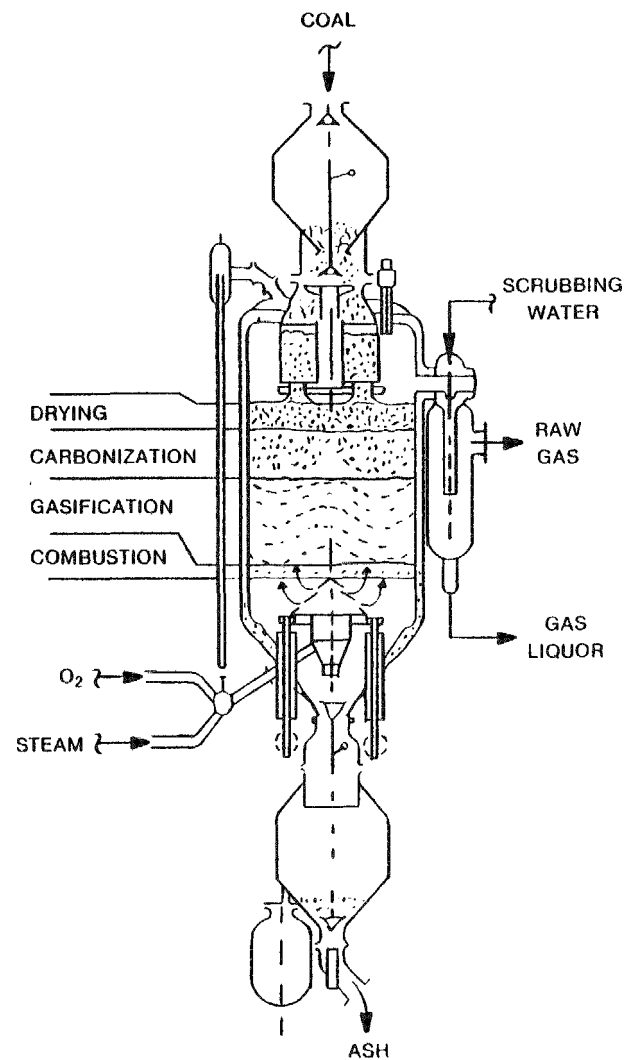
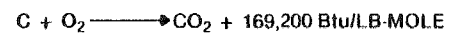
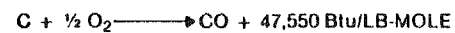
The following description starts at the coal pile and follows the product gas to the pipeline, noting when waste or by-product streams branch. Discussion of the major liquid and gaseous waste streams is presented following the description of the overall process.

Coal preparation is the first step in the gasification process. In order not to plug the gasifier, particle sizes must be between two inches and one-quarter of an inch. Smaller particles (fines) cause poor gas distribution or excessive bed pressure drop. Oversized coal particles will reduce reactor throughput because of their lower reactivity (low surface area to volume ratio); they are recycled to the crushers. The crushing operations involve single roll crushers, rotary breakers, cage mills, and coarse, medium and fine screening. The fines produced during the sizing operation must be burned on-site to produce needed steam, briquetted and fed to the gasifier, disposed of as a solid waste, or sold as a by-product. Belt conveyors are used to transport the lignite between storage and crushing areas. The material balance assumes 30 percent fines production during coal preparation.

The coal fines produced in the coal crushing and sizing steps are used to fire a conventional steam boiler that provides steam for the process and powers a generator to provide electricity for the plant. Oxygen is produced by liquifying air and allowing the lighter liquid nitrogen to separate from the liquid oxygen. Nitrogen is then a by-product. This process consumes electricity (for compressors) and steam.

In the Lurgi gasifier, gasification takes place in a countercurrent moving bed of coal at 300-400 psig and 1800-2000°F. A cyclic operation using a pressurized lock hopper at the top of the gasifier is used to feed in the coal. As the coal moves slowly downward through the gasifier, it encounters three process zones. In the top zone hot synthesis gas ascending from the bottom of the gasifier heats the coal and liberates the volatile hydrocarbons such as methane and various tars and oils from the coal. As the coal moves into the second zone, gasification occurs by the reaction of carbon with steam (H_2O) to form carbon monoxide (CO) and hydrogen (H_2). Finally as the coal approaches the bottom grate, carbon is burned to produce the heat required by the gasification reaction. These process zones and chemical reactions are illustrated in Figure 2.2-5. Approximately 99 percent of the original carbon in the coal is converted into either a gaseous (83 percent) or a liquid (17 percent) product. Lignite ash remaining after the final combustion reaction is removed through the bottom grate and disposed of as a solid waste.

During start-up of the gasifier, raw gas is produced which is not suitable for use. Up to 12 hours is required to bring the gasifier up to its operating temperature. The size of this stream will vary from almost zero initially to about 50% of the design gas flow before it will begin to assume medium-Btu gas properties. The temperature in the gasifier will steadily increase during start-up. Current design for gasification plants calls for the collection and incineration (flaring) of this start-up stream. Although small in terms of tons per year, since start-up gases will be emitted on an infrequent basis, they represent a significant air emission from a coal gasification unit. The operation of the Lurgi coal feed lock hopper system results in

DEVOLATILIZATION AND DRYINGGASIFICATIONPARTIAL COMBUSTION

70 1949 1

Figure 2.2-5. Process Zones and Chemical Reactions in the Lurgi Gasification Process

the release of raw process gas from the gasifier. Collecting and flaring of this gas may encounter problems with tar condensation and possible explosion.

Raw process gas from the Lurgi gasifier contains coal dust, oil, naphtha, phenol, ammonia, tar oil, ash, char, and other constituents. Water is used to cool and scrub the gas coming from the gasifier. At this point the product from the gasifier branches into a product gas stream of CO , H_2 , CH_4 , CO_2 , and sulfur species which has been cooled and scrubbed of oils, phenols, ammonia, and tars, and a liquid waste stream (called "gas liquor") which contains the liquids removed from the gas stream.

Carbon dioxide and gaseous sulfur compounds (of which 90-98 percent is H_2S) must be removed from the product gas stream to meet pipeline specifications, since CO_2 lowers the heating value of the gas and sulfur compounds present corrosion problems in the pipeline. The Lurgi Rectisol gas purification unit used to remove CO_2 and sulfur compounds uses methanol under pressure to physically absorb these CO_2 and sulfur compounds. Naphtha is also recovered by the Rectisol unit. CO_2 removal efficiency is approximately 95 percent; H_2S removal efficiency is 99+ percent. Regeneration of the methanol solution by lowering the pressure and application of heat liberates the absorbed materials. The recovered naphtha may be sold as a by-product or used as a plant fuel. There is also a small volume of liquid waste consisting primarily of water with trace amounts of phenols, cyanides, ammonia, sulfides and various organic compounds. This stream is combined with the gas liquor for treatment. The cleaned gas stream leaving the Rectisol unit, consisting primarily of carbon monoxide, hydrogen and methane, is ready for the pipeline. Table 2.2-4 displays the product gas composition.

TABLE 2.2-4. CLEANED LURGI PRODUCT GAS COMPOSITION

Parameter	
Composition - %	
H ₂	50.0
CO	30.0
CO ₂	2.0
CH ₄	15.0
C ₂ ⁺	0.6
Other	2.4
H ₂ S - grains/100 SCF	<0.2
Total sulfur - grains/100 SCF	0.2
H ₂ O - lbs/MMSCF	6
HHV - Btu/SCF	418
Nominal battery pressure limits - PSIG	315

The gaseous CO₂ and H₂S waste stream from the Rectisol gas purification unit is directed to a Stretford sulfur recovery unit where H₂S is converted to elemental sulfur. The process is based on the absorption of H₂S in an alkaline solution with subsequent liquid phase oxidation of the absorbed H₂S to elemental sulfur by metavanadate and anthraquinone disulfonic acid (ADA) salts. The treated gas from a Stretford unit is essentially free of H₂S but will contain all of the organic compounds present in the waste gas. This tail gas is incinerated using liquid hydrocarbon by-products from the gasifier. There is also a small volume liquid blowdown stream from the Stretford unit regeneration systems which is necessary to prevent an excessive buildup of nonregenerable by-products. Typical composition of this blowdown stream is given in Table 2.2-5.

TABLE 2.2-5. COMPOSITION OF STRETFORD
UNIT BLOWDOWN WATER

Component	Wt. Percent
H ₂ O	80.0
Na ₂ S ₂ O ₃	10.8
NaCNS	4.4
NaVO ₃	0.7
ADA	1.1
NaHCO ₃ +Na ₂ CO ₃	3.0

Meanwhile, the gas liquor waste stream scrubbed from the raw product gas must be treated. Typical composition of this gas liquor before treatment is shown in Table 2.2-6. The high content of tars, oils, phenols, ammonia, and biodegradable substances constitute a significant potential for environmental impact. Effective treatment of this waste stream requires sequential treatment by a combination of different processes.

The first requirement in any of these processes is the removal of suspended solids, tars, and oils. Gravity separation followed by multi-stage filtration is the most common approach.

The resulting wastewater is fed to a Phenosolvan unit where dissolved organics (mostly phenols) are removed. The Phenosolvan process is a liquid-liquid extraction process involving contacting the phenol-rich wastewater with one of several solvents and then regenerating the solvent and purifying the phenols. The phenols are incinerated in the plant fuel system.

TABLE 2.2-6. COMPOSITION OF UNTREATED LURGI GAS LIQUOR

pH	8.9
Chemical Oxygen Demand (COD)	12,500 mg/l
Biological Oxygen Demand (BOD)	7,500 mg/l
Total Dissolved Solids (TDS)	2,200 mg/l
Total Suspended Solids (TSS)	5,000 mg/l
Fatty Acids	1,500 mg/l
Phenols	3,500 mg/l
Ammonia	11,200 mg/l
Total Organic Carbon (TOC)	4,200 mg/l

A Phosam-W unit is used to remove ammonia compounds from the phenol-free wastewater system by steam stripping and pH adjustment. The effluent is then sent to a biological treatment unit for removal of fatty acids, cyanide compounds and residual phenols. This is followed by clarification and then final polishing by activated carbon absorption units before final wastewater discharge. It is anticipated that the sludge produced in the biological treatment facility will contain a variety of toxic organics and trace elements.

The quality of fully treated wastewater based on engineering estimates is shown in Table 2.2-7. The volume of this discharge is estimated at 1000 gpm. Because of the extremely limited number of systems currently operating, adequate empirical data on treated wastewater quality is not available. A comparison of the gas liquor waste streams for coal gasification and coke production in the steel industry is presented in Section 2.2.2.2.

TABLE 2.2-7. COMPOSITION OF TREATED LURGI
GAS LIQUOR WASTEWATER

pH	8.0
COD	100 mg/l
TSS	<1 mg/l
Phenols	1 mg/l
Ammonia	200 mg/l

Source: Rolke, 1980

Other plant wastewater streams such as from the boiler feedwater treatment facility are primarily inorganically contaminated and can be sent to a reverse osmosis unit for brine volume reduction and recycling of recovered water. The reverse osmosis concentrate brine could be discharged to a receiving surface water body or deep-well injected. Total dissolved solids (TDS) in the brine typically range from 3,000 to 4,000 mg/l.

2.2.2.2 Environmental Issues

The selection of one treatment approach for emission control of one media (air emissions) has a pronounced effect on the treatment options required of another media (liquid effluents). There are several feasible combinations of air and water treatment systems that will be considered in setting effluent/emissions standards for gasification plants. Also, it is expected that as this technology is brought on stream, improvements and modifications of both gasification and waste treatment technology will occur. For this analysis, a reasonable set of options was chosen as discussed in the previous section. The environmental residuals from these options are discussed below.

Air Emissions

The major gasification plant air emissions can be grouped into the gasification area, the power generation area, and the coal handling area. In the gasification area, the major emission source is the Stretford unit tail gas incinerator. SO_2 , NO_x , and particulate emissions from the incinerator are estimated in Table 2.2-8. Sulfur emissions from the incinerator are due to sulfur in the Stretford unit tail gas and in the tar oil used as an incinerator fuel. The H_2S and COS content of the Stretford unit tail gas are estimated at 100 ppm each. The tar oil was assumed to have a sulfur content of one percent.

The NO_x emissions from the incinerator were based on an emission factor of 45.57 tons NO_2 per 10^{12} Btu released. The particulate emissions were estimated using EPA emission factors for industrial boilers of 10 lbs. of particulates per 1000 gallons of No.5 residual oil.²

Other than from the Stretford unit tail gas, sulfur and hydrocarbon emissions from the gasification area come from lock hopper exhaust gases, gas/liquor separation area vent gases, Stretford oxidizer off gases, gas purification system off gases, ammonia recovery area off gases, and fugitive emissions from leaking valves, flanges, pumps and compressors. However, due to process data limitations, emissions from these sources were not estimated.

TABLE 2.2-8. STRETFORD UNIT TAIL GAS INCINERATOR EMISSIONS
FOR 150 BILLION BTU PER DAY PLANT

Heat Release From Incinerator MMBtu/hr	Total SO ₂ Emissions From Incinerator- Tons/yr	NO _x Emissions ¹ Tons/yr	Particulate Emissions ² Tons/yr
240	1600	96	83

¹NO_x emissions: 45.57 tons/10¹² Btu.

²Particulate emissions: Tar Oil = 10 lbs/10³ gal.

The major emissions from the power generation area are the flue gases from the steam generation boiler. Table 2.2-9 presents the SO₂, NO_x and particulate emissions factors and the emissions expected based on the June, 1979 New Source Performance Standards (NSPS) for coal-fired steam generation facilities and assumes that these NSPS are applicable to large industrial boilers.

Particulate emissions will be the major air pollutant emitted from the coal handling and preparation area. Due to lack of detailed process information, particulate emissions from the gasification plant were not estimated. However, present NSPS regulations limit the opacity of gas streams from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal to 20 percent. Although presently there are no standards for pneumatic conveying equipment processing subbituminous coals or lignite, standards exist for pneumatically conveying bituminous coals.

TABLE 2.2-9. COAL-FIRED BOILER AIR EMISSIONS FACTORS
AND AIR EMISSIONS¹

<u>EMISSION FACTORS-POUNDS PER 10⁶ BTU</u>	
SO _x	0.52 ²
NO _x	0.6
Particulate	0.03
<u>BOILER EMISSIONS - TONS PER YEAR</u>	
SO ₂	6,303
NO _x	7,273
Particulate	364

¹For coal-fired steam generation facilities > 250 MMBtu/hr.

²For coal-fired power generation facilities (electric utilities) requires 85 percent sulfur removal with a minimum level of 0.2 pounds SO₂ per MMBtu and a maximum level of 1.2 pounds SO₂ per MMBtu.

These standards limit bituminous particulate emissions to .018 grains per dry scf for pneumatic conveying equipment.

The whole area of fugitive emissions from coal gasification systems is one about which little is known. Because of the potentially hazardous nature of many of the components in the raw product gas from a coal gasifier and to protect operator safety, it is recognized that it will be necessary to take all reasonable steps to minimize these emissions. At the same time, however, no meaningful documentation of the severity of this problem has been reported in the literature. Clearly, it is inevitable that some inadvertent release of hazardous materials

from the gasification operation will occur. Knowledge as to the levels to which these emissions can be controlled with current technology is a significant gap in the existing gasification system environmental data base.

Wastewater Discharges

Wastewater can be divided into two categories: those organically contaminated by the refractory organics of the gasification process and those inorganically polluted streams from the various treatment/recovery processes. The volume of each waste category is estimated at 1000 gpm.

Inorganic waste streams consist primarily of brine from the steam plant boiler feed water treatment system, the reverse osmosis unit concentrate, and a small volume of blow-down water from the Stretford sulfur recovery unit. Because of the presence of vanadium compounds, ADA, cyanides and thiosulfates (Table 2.2-6), the Stretford unit blowdown must be treated by one of several alternative control processes prior to being discharged or reused.

For the organically contaminated wastewater, methods developed by the steel industry to cope with coke oven effluents have been used as the template for coal conversion wastewater treatment. Both gasification and coke production leave waste streams that have similar characteristics, and though coal conversion will be on a larger scale, the unit treatment operations are basically the same. These treatment steps include clarification to remove suspended material, phenol removal, ammonia stripping, biological oxidation (activated sludge), and carbon absorption as outlined in Section 2.2.2.1.

A comparison of some water quality parameters from untreated coke oven and Lurgi gasifier effluents is shown in Table 2.2-10. Although based on these parameters the wastewaters appear to be similar, there may be significant differences on a compound specific basis. Laboratory studies have indicated that nonextractable organic carbon is higher for gasification wastewaters than for coke oven wastewaters (Collins, undated). This difference implies that the treatability and toxicity of gasification and coke oven wastewaters may be different.

TABLE 2.2-10. COMPARISON OF PROCESS WASTEWATERS

	Coke Oven Ammonia Liquor mg/l	Lurgi Gas Liquor mg/l
pH	8.4	8.9
Suspended Solids	4,000	5,000
Phenol	1,000	3,500
COD	10,000	12,500
Ammonia	5,000	11,200

Total wastewater discharges are estimated at 2000 gpm. The exact volume of discharge to a receiving stream is site dependent. Where a high rate of evaporation exists, evaporation ponds may make zero discharge achievable. Elsewhere, discharge can be directly to a receiving stream or through a sediment detention pond where further biological oxidation will occur before release to off-site streams or deep well injection.

Over 200 compounds have been identified in the untreated process condensates from various coal gasification facilities. A summary listing of the organic compound classes found in these wastes is given below.

Alkenes	Polyhydrics
Alkyl Halides	Fused Ring Hydrics
Ethers	Polycyclic Aromatic Hydrocarbons
Alcohols	Non-Alternate Polycyclic Aromatics
Aldehydes	Heterocyclic N Compounds
Carboxylic Acids	Polycyclic N Compounds
Aromatic Amines	Pyrrole and Fused Ring Derivatives
Thiols	Heterocyclic S Compounds
Phenols	Heterocyclic O Compounds

Table 2.2-11 identifies several compounds found in the untreated gasification wastewater that are toxins or carcinogens specifically identified by the EPA as priority pollutants or are known to be toxic. Discharge of these pollutants would likely be controlled and monitoring for treatment removal efficiency required to obtain an NPDES permit.

Any discussion of treated effluent quality must eventually turn to what limits or standards for effluent quality will be promulgated for this industry category by the EPA. Limits for conventional (BOD, COD, TSS) and toxic pollutants identified in the wastewater are based on achievable or demonstrated pollution control technology. These limits are still under development for Lurgi gasification plants, although there is some treatment technology guidance. The limits for the coke oven industry are also under development but are far enough along that there are published estimates of final effluent quality based on a series of treatment options similar to those proposed in this module. These

TABLE 2.2-11. UNTREATED PROCESS CONDENSATE:
(ORGANIC) POLLUTANTS AND OTHER
POTENTIALLY HARMFUL COMPOUNDS

Compound	Estimated Concentration (mg/l)	Environmental Effects
Phthalates	0.7	Toxic
Phenols	650	Carcinogenic, Mutagenic, Toxic
Cresol	1,000	Toxic
C ₂ -Alkylphenol	300	Toxic
C ₃ -Alkylphenol	6	Toxic
Dihydrobenzene	10	Toxic
Naphthalene	0.8	Toxic
Acenaphthalene	0.4	Toxic
Benzoperylene	0.9	Toxic

Source: Page, 1980

limits, shown in Table 2.2-12. are one estimate of those that might be expected for the Lurgi coal gasification process. In developing limits, the EPA selects parameters that indicate the relative efficiency of removal by best available control technology, be it biological, physical or chemical treatment. The first eight parameters are those likely to be selected as indicator parameters (requiring monitoring).

It should be noted that pollution control strategy for existing coke ovens versus new coal gasification projects are distinct. Because the steel industry developed before the passage of current pollution control requirements, pollution regulation has been gradual. Because the coal gasification industry is emerging, it is anticipated that these plants will include more extensive pollution control technology.

TABLE 2.2-12. BEST AVAILABLE TECHNOLOGY EFFLUENT LIMITATIONS
GUIDELINES FOR BY-PRODUCT COKE MAKING BIOLOGICAL
TREATMENT SYSTEMS

BAT LIMITATIONS	
CRITICAL PARAMETERS	mg/l*
Cyanide, total	1
Phenolic compounds	0.05
Ammonia, as N	15
Oil and grease	10
Suspended solids	40
Sulfides	0.3
Thiocyanates	0.5
pH	6-9
Acrylonitrile	0.01
Benzene	0.05
Chloroform	0.05
Ethylbenzene	0.02
Fluoranthene	0.01
Naphthalene	0.01
Phenol	0.01
Phthalates, total	0.06
Benzo(A)Anthracene	0.01
Benzo(A)Pyrene	0.01
Acenaphthylene	0.02
Fluorene	0.01
Pyrene	0.02
Toluene	0.05
Xylene	0.01

*mg/l based on 218 gallons of effluent per
ton of coke produced

Source: USEPA-Effluent Guidelines Division,
1979

Solid Waste

Table 2.2-13 presents the solid waste emissions from the coal gasification plant. These emissions are based on the ash and sludge rates from the plant material balance. Unused coal fines can be disposed of in the mine. Most if not all of the organics in the lignite fed to the gasifier will be consumed in the combustion process within the gasifier and in that respect they will be similar to boiler ash. The classification of coal ash as a high volume, nonhazardous waste is in effect until further studies can be completed and special treatment guidelines developed. The activated sludge from the biological treatment facility may contain significant toxic organic and trace metal levels and thus require handling as a hazardous waste.

TABLE 2.2-13. SOLID WASTE FROM LURGI GASIFICATION PLANT

Coal Fines ¹ (TPD)	Gasifier Ash ² (TPD)	Boiler Ash ² (TPD)	FGD Sludge ³ (TPD)	Ash and FGD Sludge ⁴ (ac-ft/yr)	Biological Sludge ⁵ (TPD)	(ac-ft/yr)
900	2175	795	615	470	70	14

¹ As received moisture content (35 percent)

² 80 percent solids

³ 35 percent solids

⁴ 70 percent solids; s.g.=1.73 ; 299 stream days per year

⁵ 20 percent solids; s.g.=1.04 ; 299 stream days per year

2.2.3 MBG Transportation Module

2.2.3.1 Technology Description

Because of the lower heat content and distinct chemical composition of MBG relative to natural gas, transmission of MBG in an existing natural gas pipeline is unlikely to occur. Instead, a new pipeline would be specifically built to transport MBG from the gasification facility to the ultimate consumer. This study assumes that this consumption would occur in industrial boilers located in a major Gulf Coast industrial center. Although the actual route and length of such a pipeline would depend on site-specific factors not considered in this analysis, it is anticipated that the distance would not exceed 200 miles.

The MBG transmission system operating pressure and pipeline diameter are dependent on the actual route. The outlet pressure of the gas from the Lurgi gasification plant is 315 psig. It is desirable to deliver the gas to the distribution center at approximately 200 psig in order to be compatible with the pressure of most existing in plant gas systems. It is anticipated that for 42 inch OD pipe, no compression will be required to deliver MBG up to a distance of approximately 200 miles. Greater route lengths may require additional gas compression or larger diameter pipe.

Construction of the pipeline is accomplished by the traditional cut and fill procedure. River and highway crossings are constructed using established methods. The pipe is carbon steel with a wall thickness which allows for Class 2 operation at a maximum pressure of 400 psig.

A characterization of the gas being transported and the gas specifications required by potential users are presented in Tables 2.2-4 and 2.2-14. Over 80 percent of the gas consists of carbon monoxide (CO) and hydrogen (H₂). The nature of this gas presents three major corrosion considerations: 1) hydrogen embrittlement, 2) CO₂/H₂O acid formation, and 3) H₂S effects. Hydrogen embrittlement is not expected to be a problem at temperatures less than 475°F in carbon steel pipe. Interstage cooling in the compressors (when required) will eliminate any potential for hydrogen embrittlement at the compression station. CO₂/H₂O acid formation will not occur as long as no liquid water is present. A dehydration chamber at the gasification plant insures that this condition is met.

For controlling corrosion by H₂S, the design maximum concentration of H₂S at 0.2 grains/100 scf was set for three reasons. First, any concentration of H₂S significantly greater than 0.2 gr/100 scf can affect odorant requirements. Second, concentrations of H₂S above 0.5 gr/100 scf in a full line will tarnish and eventually plug any bronze or brass control orifices in either the pipeline or the process equipment. Third, at concentrations greater than 1.0 gr/100 scf pipeline corrosion begins to occur.

2.2.3.2 Environmental Issues

The environmental impacts from construction and operation of an MBG pipeline should be minimal. Impacts from pipeline construction in most cases are localized and short-term. Potential impacts from construction include:

- an increase in noise level from heavy earth-moving equipment;

TABLE 2.2-14. PRODUCT GAS SPECIFICATIONS

Component	Specification
Btu's per scf	300+
Consumption site pressure - psig	200+
Temperature - °F	<120
CO ₂ - %	2-3
H ₂ O - lbs/10 ⁶ scf	<6
H ₂ S - grains/100 scf	<0.2
Total sulfur - grains/100 scf	0.2
Hydrocarbon dew point @ 815 psia - °F	<15
Nitrogen plus Argon - %	<1

- disturbances to plants and wildlife;
- short term disturbances of surface waters at river crossings; and
- localized air pollution from fugitive dust at active construction areas.

The major impacts of pipeline operation are 1) noise at compression and metering facilities and around valves and 2) leaks. An MBG pipeline's potential for noise pollution is no different than that from any other large gas pipeline. Standard noise screening methods can be used to minimize the noise impacts.

The problem of gas leaks could result from faulty valves, pressure problems, or pipe corrosion. Leaking gas could be ignited upon contact with air and an ignition source such as a spark or flame. In addition, CO and H₂S are both lethal gases. Case studies of existing CO and H₂ gas pipelines have indicated that no special extensive precautions are necessary for safe operation. However, these pipelines have been of much shorter length and are generally in industrial areas rather than in less controlled urban and rural areas. Previous experience with shipment of CO and H₂S in municipal "town gas" systems was at lower pressure (5 psig) and lower CO concentrations.

2.2.4 MBG Utilization Module

2.2.4.1 Technology Description

The end use of the coal-derived MBG can be as a fuel gas in industrial boilers and as a feedstock in various chemical processes. For comparison with the direct coal firing scenario (Section 2.3) and because of the focus of federal fuel use policy on boiler fuels, only the fuel gas option is considered in this analysis. From a comparative standpoint, the demand for MBG in large industrial boilers in the Gulf Coast is estimated to be between two and five times greater than as a feedstock.

Depending on the pressure and temperature of steam produced in an industrial boiler, 150 billion Btu per day of fuel input will produce between 4 and 5 million pounds of steam per hour. Only the largest of industrial plants in the U.S. consume this much steam; generally an industrial plant with a total steam demand of one million pounds per hour of steam demand is considered large. As a result, it is anticipated that the output of the gasification plant would have to be used in a number of

separate boilers rather than in a single unit. As a result the impacts from utilization of MBG will be dispersed over the area in which the MBG is distributed.

Figure 2.2-6 illustrates the basic processes of an industrial boiler. Fuel and air are fed to the furnace providing the heat to convert pretreated water to steam. The steam is then piped to various processes for use. The condensed steam is recycled back to the boiler for reheating. The specifics of the processes of pre-treating the water and condensing the steam are not dependent on the type of fuel used and therefore are not discussed in this module.

Substitution of MBG for natural gas in industrial and electric utility boilers can frequently be accomplished with minimal piping and burner changes. As shown in Table 2.2-15, the heating value of the fuel/air mixture for MBG is substantially similar to that of natural gas. Because of the higher flame temperature and lower flue gas volume, increases in boiler rating may actually occur with the substitution of MBG. Potential constraints on the retrofit of MBG into existing facilities include changes in the burner system in order to achieve flame stability and shape requirements, and specific combustion or heat release rate requirements.

TABLE 2.2-15. MBG COMBUSTION CHARACTERISTICS

Fuel	Heating Value Btu/scf	Flame Temp. °F	Volumes @ 15% Excess Air scf/Btu				Mixture Heating Value Btu/scf
			Fuel	Air	Mix	Flue Gas	
MBG	298	3,767	3,584	8,900	12,484	11,260	85.6
Natural Gas	970	3,279	1,145	12,340	13,485	13,480	82.4

Source: Booz, Allen and Hamilton, Inc., 1979.

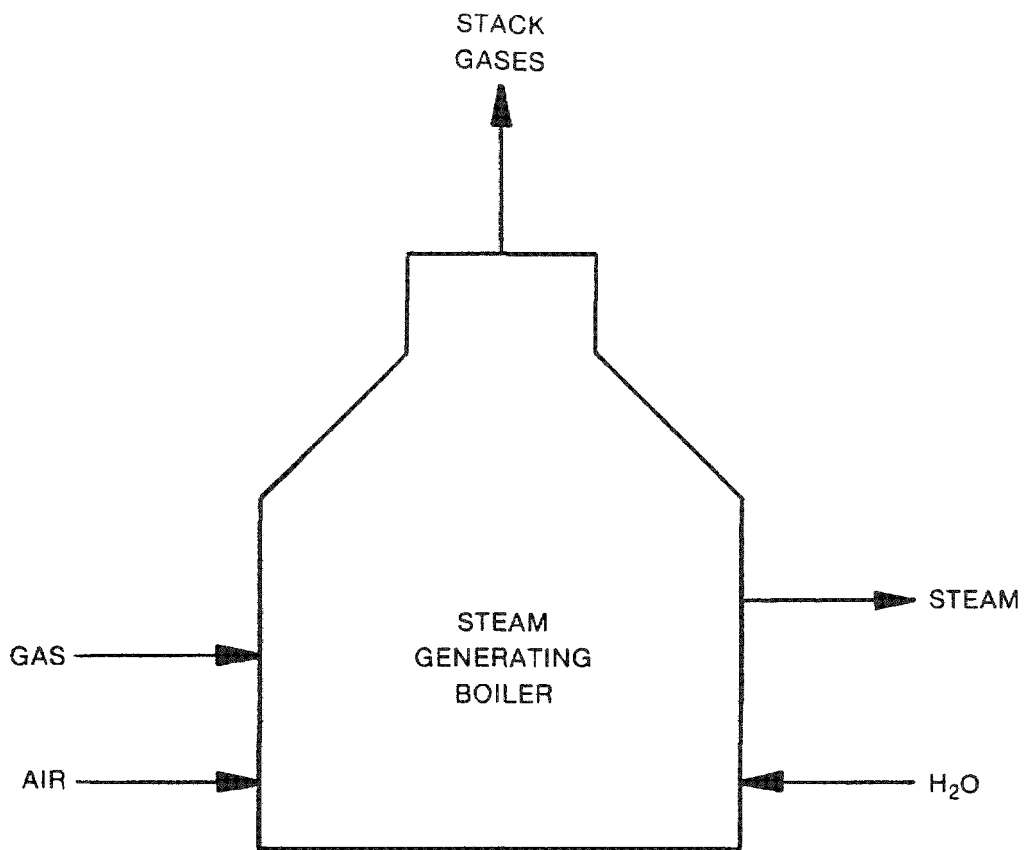


Figure 2.2-6. Basic Process of a Gas-Fired Industrial Boiler

For analysis of emissions, an existing boiler system employing a two-staged combustion operation is assumed. The purpose of staged combustion is to reduce potential NO_x emissions. In two-staged combustion the burners are operated fuel rich by introducing only 80 to 95 percent stoichiometric air (the theoretical amount of air required for complete combustion) at the burner. Combustion is completed by air injected above the flame

zone through second stage "NO-ports." NO_x emissions are reduced because the bulk of combustion occurs under fuel-rich, reducing conditions and because of lower flame temperatures.

2.2.4.2 Environmental Issues

Because no ash is produced from the combustion of MBG, flue gas is the only waste stream associated with the use of this fuel. These gases are released untreated; therefore, no liquid or solid waste streams typically associated with air pollution control technologies are generated. The complete operation of an industrial boiler does produce other liquid and solid waste streams from processes such as feed water pretreatment and cooling tower blowdown. In addition, a fairly large water resource is required to provide the necessary amount of cooling water to condense the steam. These waste streams and water resource requirements, however, are independent of whether MBG or direct-fired lignite is used and are therefore not considered.

Table 2.2-16 presents emission factors and New Source Performance Standards (NSPS) for gaseous-fired steam generation boilers. The emission factors for natural gas fired boilers were derived by EPA for a wide range of industrial and utility boilers.³ These emission factors can be used for estimating pollutant emissions from boilers constructed before August of 1971. Emissions from boilers built or modified after August of 1971 must comply with EPA NSPS as also shown in Table 2.2-16. Total emissions from firing MBG were derived using both the EPA emission factors and the NSPS assuming a fuel use rate of 150×10^9 Btu/day. The gas cleaning technology in the gasification plant (see Section 2.2.2.1) removes 99+ percent of the sulfur particulates in the coal from the product gas stream.

TABLE 2.2-16. STEAM GENERATION EMISSIONS FOR 150 MMBtu/D OF
MBG NEW SOURCE PERFORMANCE STANDARDS AND
ESTIMATED TOTAL EMISSIONS

POLLUTANT	EPA - Derived Emission Factors For MBG Lbs/mm Btu ¹	Total Emission Based On EPA Emission Factors Tons/Year	Existing NSPS For Gaseous Fossil Fuels Lbs/mm Btu ²	Total Emissions Based On Existing NSPS Tons/Year
SO ₂	0.0014 ³	41 ³	NA	---
NO ₂	0.7	19,160	0.5 ⁴	13,686
Particulates	0.005 - 0.015	140 - 410	0.1	2,740
Hydrocarbons	0.003	82	NA	---
CO	0.017	465	NA	---

¹Industrial boilers >100 MMBtu/hr constructed before August 1971.

²Steam generation boilers >250 MMBtu/hr. For boilers built, constructed, or modified after August 1971.

³Based on a sulfur content = 0.2 grains/100 scf and a gas quality of 400 Btu/scf.

⁴Based on NSPS for Electric Utilities.

As a result the environmental emissions from combustion of MBG require no additional controls with regard to these two pollutants. The sulfur content of 0.2 grains of sulfur per scf of MBG gives an emission factor of 0.0014 pounds of SO_2 per million Btu versus an emission of 0.0006 pounds of SO_2 per million Btu from natural gas with 0.2 grains of sulfur per scf. Particulate emissions are not expected to differ significantly from levels experienced with natural gas. Hydrocarbon and CO_2 emissions are similar to natural gas also.

Nitrogen oxides are formed from both the conversion of nitrogen compounds in the fuel and the thermal fixation of atmospheric nitrogen. As with the removal of sulfur compounds during gasification product gas cleanup, the removal of ammonia and cyanide compounds eliminate the majority of nitrogen compounds in the product gas. As a result, the primary source of nitrogen oxides from MBG combustion is expected to be through thermal fixation of atmospheric nitrogen. The higher flame temperature of MBG promotes thermal fixation and can result in an increase in NO_x emissions versus natural gas use. However, proper use of two-stage combustion and other combustion modification techniques can make this difference negligible.

2.3 Direct Firing Scenario

The direct firing scenario is composed of the three primary components shown in the lower half of Figure 2.1-1. These components are:

- a mining module consisting of a 4.2 million ton per year surface mine,

- a transportation module consisting of two 60 car unit trains, and
- a utilization module consisting of a new lignite-fired boiler and associated environmental controls.

2.3.1 Direct Use Mining Module

2.3.1.1 Technology Description

The technology description for the surface mining of lignite in the Direct Use Scenario is similar to that described previously in Section 2.2.1.1 for the MBG Mining Module. Because of the 30% energy loss associated with gasification of the lignite, the mine required for direct firing of lignite is 4.2 mtpy as compared to 6.0 mtpy in the gasification scenario. A mine of this size would require mining approximately 260 acres per year assuming a lignite seam thickness of 7-8 feet. The total disturbed area at any given time (including partially reclaimed land) would be about 850 acres. Process flow and waste streams for the direct use mine are the same as shown in Figure 2.2-2.

Water requirements at a 4.2 mtpy mine are estimated at 1260 acre feet per year (af/yr), mostly for watering haul roads, spraying lignite storage areas, and other dust control activities. Further discussion of water requirements and uses is presented in Section 2.2.1.2.

2.3.1.2 Environmental Issues

The environmental issues associated with a 4.2 mtpy lignite surface mine include resource requirements and pollutant emissions. Primary resource requirements are the lignite reserves, water resources, land resources, and the work force to operate the mine. Major pollutant emissions are sedimentation pond discharges and fugitive dust emissions.

Air Emissions

Air pollutants associated with surface mining are primarily fugitive dust emissions from haul roads, overburden removal, and lignite storage. These primary emissions have been estimated using the "EPA Region VIII Interim Policy Paper on the Air Quality Review of Surface Mining Operations." For a 4.2 mtpy mine the estimated fugitive emissions are given below in Table 2.3-1.

Wastewater Discharges

As in the case of the 6.0 mtpy mine required in the gasification scenario, the 4.2 mtpy mine would include sedimentation ponds with an extremely variable discharge rate. Surface runoff entering the pond is estimated at 750 af/yr and the pit seepage water is estimated at about 160 af/yr. The total annual flow into the pond is 910 af/yr. Estimated water requirements for the mine of 1260 af/yr exceed sedimentation pond inflow by 350 af/yr. It is estimated that the pond may discharge for a short period after significant rainfall events, but otherwise would probably not discharge. Supplemental ground water may be required to make up water requirements not satisfied by the sedimentation ponds.

TABLE 2.3-1. FUGITIVE EMISSIONS FROM A
4.2 MTPY SURFACE MINE*

Process	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Controlled Emissions (tpy)
Haul Roads	1280-6330	85	192- 950
Overburden Removal	333-2080	-	333-2080
Stockpile Erosion	488	50	244

*The ranges reflect differences in mine depth, distances to storage facilities and other factors which will vary with time.

Allowable concentrations of sedimentation pond discharges for various pollutants associated with surface mines are the same as in the MBG scenario (see Table 2.2-1).

Solid Waste

Although overburden is not normally considered a solid waste, the volume of overburden expected at a 4.2 mtpy surface mine would range from about 7800 af/yr to near 52,000 af/yr.

2.3.2 Direct Use Transportation Module

2.3.2.1 Technology Description

Transportation can be a significant factor in the total cost of coal delivered to the final consumer. In order to reduce transportation costs, increasing use is being made of the unit train concept for moving coal by railroad. Introduced during the late 1950s, a unit train (also referred to as a shuttle train) in normal coal service is composed of three to five locomotives and

up to one hundred, 100-ton capacity hopper cars which remain coupled together throughout a movement of coal from the mine to the consumer and the return of the empty train to the mine for reloading (Figure 2.3-1). Specially designed loading and unloading facilities with capacities of up to 5,000 tons per hour are used. Hopper cars are designed to rapidly discharge coal into an under-track pit either by opening doors on the bottom of the cars or by installing special rotary couplings that allow the cars to be turned upside down. In both instances, the train remains in essentially constant motion throughout its operation. The continuous cycling and integral operation of the train set allows the railroad to increase the productivity of equipment, to reduce operating costs, and to retain a competitive advantage with regard to other modes of long-distance coal transportation. Environmental impacts from unit trains include:

- fugitive dust from loading, transit, and unloading operations
- carbon monoxide, hydrocarbon, nitrogen oxide and other emissions from locomotives
- land use impacts due to loading and unloading facilities and new trackage
- fires due to trains and train crews
- socioeconomic impacts to communities disrupted by unit train operations

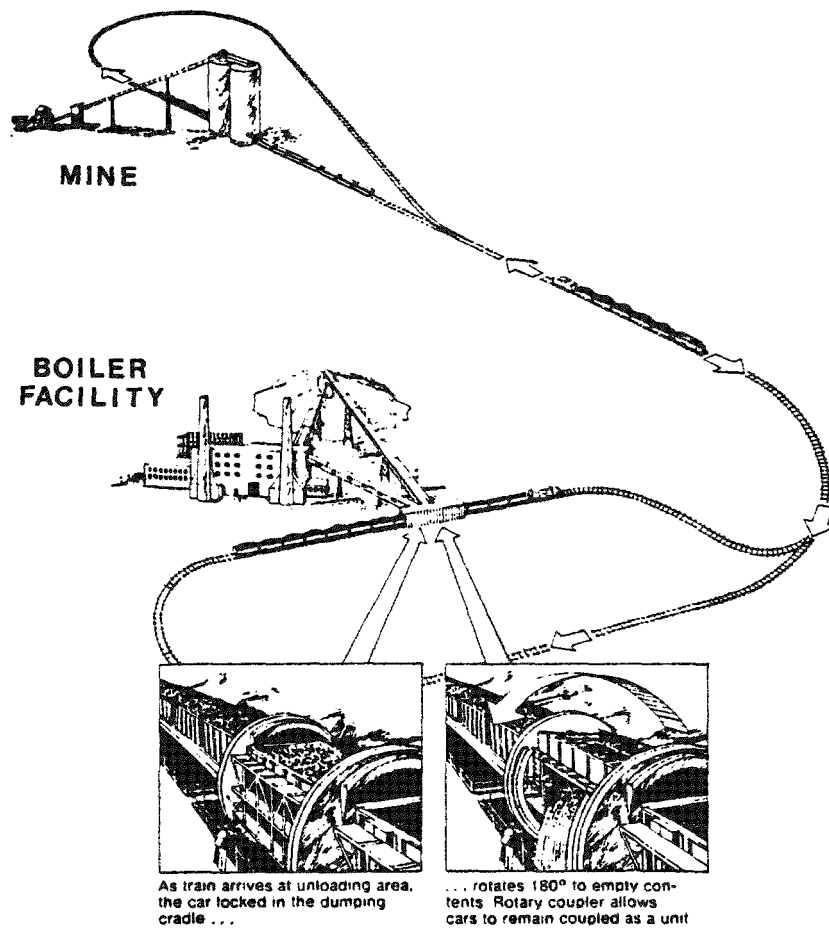


Figure 2.3-1. Coal Unit Train Transportation System

- accidents at railroad/highway grade crossings
- noise from loading, transit and unloading

Because of lignite's low energy content per ton and resultant poor transportation economics relative to other coals, little experience exists with regard to the long-distance transportation of lignite. While rail movements of North Dakota lignite to midwestern power plants several hundred miles distant have occurred, the only direct experience with the movement of lignite by train in Texas has been at the Monticello and Martin Lake power plants of Texas Utilities Company. The longest of the Texas movements is 35 miles.⁴ The analysis of environmental issues is therefore based primarily on knowledge of North Dakota lignites and analogy with other coals.

The design of the direct use transportation module is based on a coal demand at the industrial boiler of 11,500 tons per day or 4.2 million tons per year. Based on 100-ton capacity hopper cars, a total of 115 cars per day would be required. The estimated transportation distance from the mine to the industrial user is 180 miles. The unit train configuration used in the analysis consists of two trains per day composed of three 3600 horsepower locomotives and sixty 100-ton capacity hopper cars. This configuration will allow greater flexibility in system operation, reduce land requirements for track loops at the loading and unloading facilities and at sidings, and reduce train turnaround times as compared to a single train of roughly 120 cars. Based on an average unit train speed during transit of 20 miles per hour and a loading and unloading time of three hours each (versus four hours allowed for existing movements of 100 car trains), round trip time is 24 hours.

2.3.2.2 Environmental Issues

The analysis of environmental residuals associated with direct use transportation module is limited in this section to air emissions. Because of the highly route specific nature of impacts associated with land use and socioeconomics, these topics are reviewed in Chapter 3.

Air Emissions

The two major sources of air emissions from the transportation of lignite by rail are fugitive dust from hopper car loading, transit, and unloading, and emissions from diesel locomotives. The problem of fugitive dust results in part from the loss of moisture in the lignite during handling which causes the lignite to shrink, crack, and form dust particles. The high reactivity of lignite and dusting problem can also potentially result in spontaneous combustion of the lignite in the hopper car. Given the relatively short transit time of the unit train from the mine to the consumer, the problem of spontaneous combustion is not believed to be significant and has not been considered in the analysis. To control dust emissions during loading and unloading operations, water sprays and air filtering systems are commonly employed. With such systems, problems of coal dust emissions can be adequately confined to the handling facilities and their immediate surroundings. Loss of coal dust during transit, especially during the first fifty miles after loading, is frequently mentioned as a problem. While some studies have estimated that up to one percent of the coal may be lost as fugitive dust during unit train transit,^{5,6} another analysis has indicated that little scientific evidence exists to support such estimates.⁷ Differences in car weights before and after transit and ambient air quality monitoring near tracks were reported in this latter

analysis to be generally so small that they were limited by the sensitivity of analytical equipment. Should fugitive dust emissions during transit be a significant problem, use of an oil spray or other dust suppressant has been found to be an effective control technique with lignite.⁸ For the purpose of this analysis it is arbitrarily assumed that emissions of coal dust from loading, transit, and unloading operations will equal 0.5 percent of the tonnage of coal transported, or 21 thousand tons per year.

Diesel locomotives omit carbon monoxide, hydrocarbons, nitrogen oxides, particulates, and other pollutants during operation. The amount of each pollutant depends upon several factors including fuel composition, freight tonnage, and track grade. Based on locomotive fuel consumption⁹ and emission¹⁰ estimates, annual locomotive emissions for the design movement are given in Table 2.3-2.

TABLE 2.3-2. DIESEL LOCOMOTIVE EMISSIONS¹

Pollutant	CO	HC	NO _x	Particulates	Others ²
Emissions (tons/yr)	656	115	1,353	102	51

¹ Based on 8.2 million gallons of diesel fuel use per year.

² Aldehydes and organic acids.

2.3.3 Direct Firing Module

2.3.3.1 Technology Description

The basic processes involved in the direct firing of lignite include: coal preparation, direct firing, bottom ash handling and flue gas cleaning. Figure 2.3-2 illustrates the

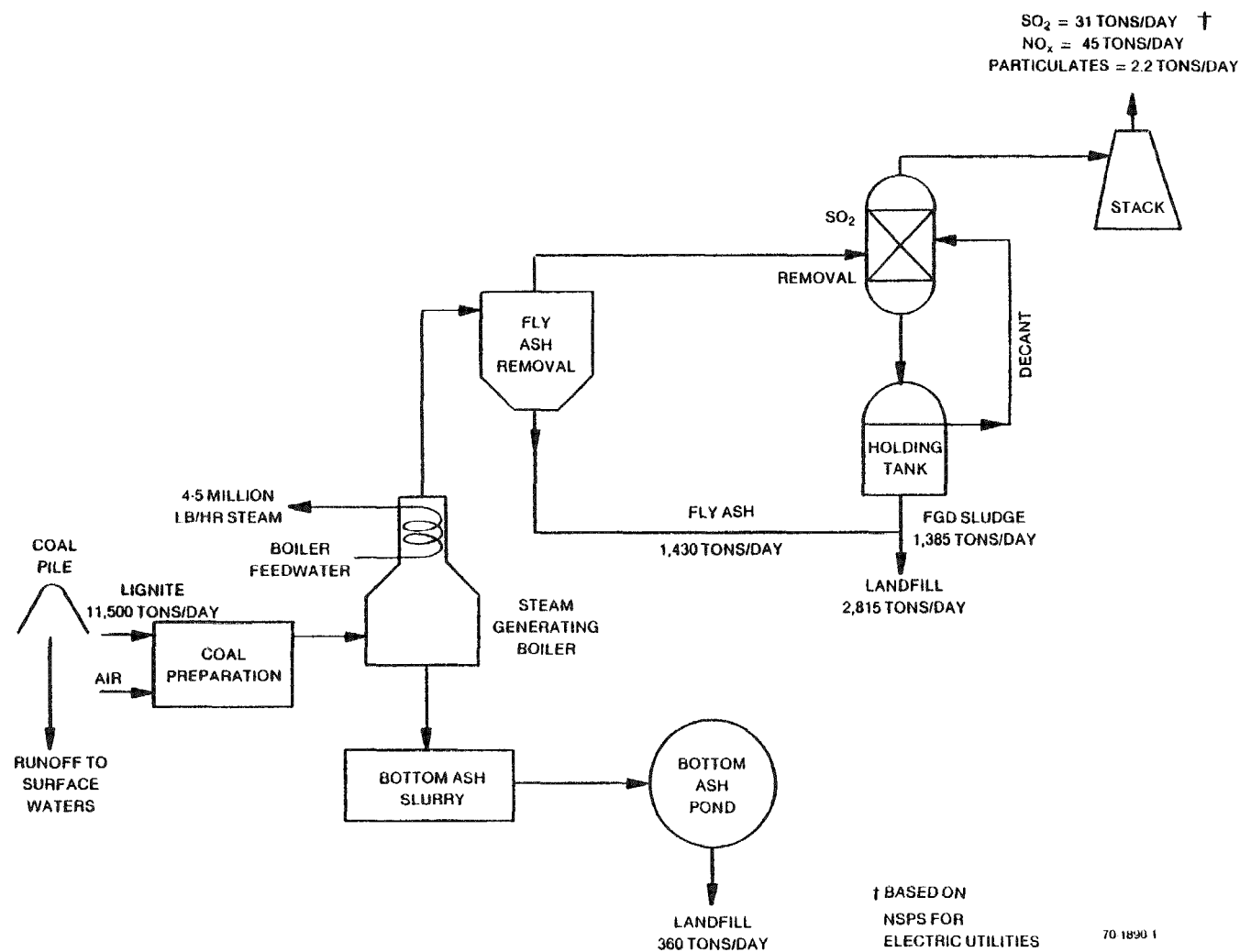


Figure 2.3-2. Direct Firing Process Flow Diagram

basic process of direct firing lignite. The quantity of lignite involved is 11,500 tons/day. Only those environmental aspects which differ significantly from direct firing of MBG are addressed. Areas not addressed include cooling water system emissions, boiler feed water treatment systems, and plant waste streams and runoff not specific to the use of coal.

As discussed in Section 2.2.4.1, 150 billion Btu per day is greater than most industrial facilities can individually consume. As a result, the projected movement of 11,500 tons of lignite per day will be either distributed to several different facilities within an area or used in a central facility developed to provide steam and perhaps cogenerated electricity to several different locations will distribute the resultant impacts over a larger area than a single central facility, and may thus reduce siting constraints such as those posed by air quality. On the other hand, these small facilities may be subject to less stringent environmental control technology requirements and may thus emit more total pollutants. This analysis assumes the construction of a single, large facility.

In order to ensure an adequate supply of lignite for steam generation, the plants will maintain an outdoor reserve in lignite storage piles. It was assumed that a 30-day supply will provide a sufficient safety factor. With a feed rate of 11,500 tons/day, this amounts to 5.2×10^5 yd³ of lignite.

The first step in the direct firing process is coal preparation. Lignite from the storage pile is dried and pulverized simultaneously in a pulverizer and moved to the burners in a continuous uninterrupted operation. Pulverization is accomplished by a combination of crushing under pressure and

attrition between grinding surfaces and lignite. The pulverizer is operated under suction, with air as the predominate means for circulating the material through the grinding zone and conveying the finished product to the burners.

The pulverized lignite is combusted in the boiler with sufficient air to ensure complete combustion. The heat generated converts water to steam which is then used in various processes, condensed and recycled to the boiler. Combustion gases are cleaned of particulates and sulfur dioxide (SO_2) and then discharged to the atmosphere. Nitrogen oxides (NO_x) and small amounts of hydrocarbons and carbon monoxide are also emitted.

There are three major by-products of lignite combustion and flue gas cleaning: fly ash, bottom ash, and scrubber sludge. The ash residues are primarily derived from the inorganic matter in the lignite. Bottom ash typically representing 20 percent of the total ash, is that part of the residue which is fused during combustion into particles heavy enough to drop to the bottom of the furnace. This ash or slag is collected and sluiced with water to a disposal pond. The pond will be periodically dredged and solids disposed of in a landfill. Fly ash, accounting for the remaining 80 percent of the ash, is that part of the ash which is entrained in the combustion gas leaving the boiler. Fly ash is removed from the flue gas through the use of a baghouse or electrostatic precipitator (ESP) and mixed with the scrubber sludge for ultimate landfill disposal.

Scrubber sludge is produced during the desulfurization process. SO_2 is removed by wet scrubbing with a slurry of lime or limestone, and subsequently, precipitated as calcium sulfite and calcium sulfate (gypsum) in a holding tank. Unreacted lime and limestone are also recovered as solids. These solids are

recovered as sludge in a solid-liquid separator and are then mixed with fly ash to increase the stabilization and fixation of the mixture. The liquid recovered from the separator is recycled to the scrubber. The mixed scrubber sludge and fly ash is disposed of in a landfill.

Water consumption associated with coal related systems--specifically ash transport and flue gas desulfurization--are estimated at 230 gpm.

2.3.3.2 Environmental Issues

The direct firing of lignite in industrial boilers will produce liquid, solid, and gaseous waste streams. Liquid effluents consist of coal pile runoff and ash pond overflow. Solid waste streams include the mixture of fly ash and scrubber sludge and the solids dredged from the bottom of the ash pond. The final major waste stream is the stack gas emissions. Figure 2.3-2 shows the sources, quantities, and receiving media of these waste streams. There are other waste streams associated with the operation of an industrial boiler, however, these are not dependent on the type of fuel used and therefore are not discussed.

Air Emissions

After fly ash and SO₂ reduction, the stack gases are discharged to the atmosphere. The major pollutants of concern when firing lignite are particulates, sulfur oxides, and nitrogen oxides. Hydrocarbon and carbon monoxide emissions are usually low under normal operating conditions. Table 2.3-3 presents EPA emission factors¹¹, NSPS for coal fired electric utilities, and the total estimated emissions based on each.

TABLE 2.3-3. EPA EMISSION FACTORS, NEW SOURCE PERFORMANCE STANDARDS AND ESTIMATED TOTAL EMISSIONS FROM THE COMBUSTION OF LIGNITE

Pollutant	EPA-Derived Emission Factors for Uncontrolled Lignite Combustion ¹ (lb/mmBtu)	Total Emissions Based on EPA Emission Factors ¹ (tons/yr)	NSPS for Coal Derived Fuels ² (lb/mmBtu)	Total Emissions Based on NSPS ¹ (tons/yr)
SO ₂	3.0 ³	81,900	0.42 ³	11,466
NO _x	0.61 ⁴	16,700	0.6	16,425
Particulates	15.4 ⁵	420,000	0.03	821
Hydrocarbons	0.023	632	NA	NA
CO	0.077	2,108	NA	NA

¹Based on lignite w/6,500 Btu/lb heating value, feed rate = 54.6×10^{12} Btu/year.

²For electric utility boilers ≥ 250 mmBtu/hr.

³Based on coal w/ sulfur content = 1.1% (as received) and sodium content of the ash = 0.4%.

⁴Assumes unit is tangentially fired.

⁵Based on coal w/ ash content = 12.5% (as received), 80% of total ash is fly ash.

Particulate emissions when operating at design conditions are small relative to sulfur and nitrogen oxide emissions. The occurrence of inhalable, fine particulates and trace elements in particulate emissions are a concern, however. Trace elements are discussed further in a following subsection.

Sulfur emissions from lignite combustion are a function of the sulfur and alkali content of the lignite. Unlike most fossil fuel combustion in which over 90 percent of the total sulfur is emitted as SO_2 , a portion of the sulfur content in lignite may react with the alkali ash components during combustion and be retained in the bottom ash and flyash.

Nitrogen oxide emissions are a function of the nitrogen content of the fuel and boiler design. Texas lignites have an average nitrogen content of 0.7%. This nitrogen is readily converted to NO_x during combustion. Thermal fixation of atmospheric nitrogen at high combustion temperatures can be reduced through the proper design of the boiler's firing configuration and control of excess air (see Section 2.2.4.1).

Wastewater Discharges

As stated earlier, $5.2 \times 10^5 \text{ yd}^3$ of coal will be stored at the boiler site. Assuming a square base, 15 foot height, and 1:3 slope at the sides of the pile, this represents a surface area of 23.5 acres. The quantity and quality of runoff from the pile is dependent on a number of variables including the composition of the lignite, the amount of rainfall, and the control technology used. Good predictive tools for quantifying the amount and quality of runoff in this study were not available. In general, however, the major pollutants of concern are TSS, TDS, sulfates (SO_4),

and iron. The concentrations of sulfates and iron are dependent on the sulfur and pyrite concentrations in the lignite. The lignite used in this scenario is low sulfur and has relatively low pyrite concentrations. Consequently, sulfate and iron concentrations in the ash pond effluent should be fairly low. Coal pile runoff from steam-electric plants is currently regulated by EPA. These regulations limit effluent TSS to 50 mg/l and pH to 6.0-9.0. Control of TSS and pH typically will also reduce the concentrations of metals.

The ash pond overflow (bottom ash sluice water) of 150 gpm will be discharged to nearby surface waters. Proposed EPA regulations limit the TSS and oil and grease concentrations of discharges from power plants. These regulations are presented in Table 2.3-4. Similar standards may be applied to industrial boilers in the future. Table 2.3-5 presents the characteristics of ash pond overflows (not lignite specific) that have been treated for TSS removal. The concentrations of metals are all within acceptable levels.

TABLE 2.3-4. DISCHARGE LIMITS ON BOTTOM ASH TRANSPORT WATER FOR STEAM-ELECTRIC PLANTS

	Maximum For Any One Day (mg/l)	30-Day Average (mg/l)
TSS	100	30
Oil and Grease	20	15

Source: Federal Register, October 14, 1980

TABLE 2.3-5. CHARACTERISTICS OF ASH POND OVERFLOWS WITH TOTAL
SUSPENDED SOILS CONCENTRATIONS LESS THAN 30 mg/l

Capacity (MW)	No. of Samples	TSS	Fe	Cu	Cd	Ni	As	Pb	Hg	Zn	Se	P	Cr	Oil & Grease
1,341 ¹	7	16.5	0.63	0.01	-	0.01	0.19	0.14	0.0001	0.04	0.011	-	0.01	4.0
511 ²	5	4.4	0.11	0.006	0	0.0004	0.02	0.004	0	0.005	0.004	-	0.004	1.3
600 ³	1	15	-	0.11	0.002	-	0.06	0.01	0.0001	0.04	-	-	0.02	-
694 ²	3	20	0.52	0.15	-	0.005	0.21	0.007	0.0001	0.02	0.01	-	0.005	0.79

¹subbituminous coal

²bituminous coal

³lignite

Source: USEPA, 1980

Solid Wastes

As stated earlier, the boiler solid waste streams consist of bottom ash and the mixture of scrubber sludge and fly ash. In pulverized firing of lignite, approximately 20 percent of the ash is bottom ash and 80 percent is in the form of fly ash. The principal components of limestone or lime scrubber solids are calcium sulfite, gypsum, and calcium carbonate. The concentration of these species is dependent upon the SO₂ and oxygen concentrations in the flue gas prior to scrubbing, the type of scrubber system, and the operation of the scrubber. Based on design lignite of 12.5% ash and 1.1% sulfur, the solid waste streams are quantified in Table 2.3-6. Assuming a landfill depth of 30 feet, this amount of solid waste would require approximately 14.7 acres of landfill per year for disposal or 434 acres during a design life of 30 years.

TABLE 2.3-6. SOLID WASTE FROM LIGNITE-FIRED BOILER

Boiler Ash ¹ (TPD)	FGD Sludge ² (TPD)	Ash and FGD Sludge ³ (ac-ft/yr)
1790	1385	434

¹ 80 percent solids

² 35 percent solids

³ 70 percent solids; s.g. = 1.73

2.4 Comparison of Resource Requirements and Environmental Residuals

The objective of Section 2.4 is to identify the natural resource and environmental tradeoffs associated with the mine-mouth conversion of lignite to MBG and shipment of gas to industrial users on the Texas Gulf Coast (Section 2.2) versus the direct use of lignite by these same users (Section 2.3). Emphasis is on the quantification of requirement/residuals as a function of location. Table 2.4-1 compares the lignite and water resource requirements and air, solid waste, and wastewater residuals of the MBG and direct firing scenarios. This comparison is graphically presented in Figure 2.4-1.

2.4.1 Lignite Requirements

Lignite requirements under the MBG scenario (6.0 million tons per year) are 43% higher than in the direct firing scenario (4.2 million tons per year) due to the energy loss associated with lignite gasification. Over the life of the gasifier or coal-fired boiler (assumed to be thirty years), this would equate to the difference between a lignite deposit of 200 million tons versus one of 140 million tons (assuming 90% recovery).

2.4.2 Water Requirements

The primary impact on water requirements under the MBG scenario is to increase the use of water in the lignite belt. The major source of water use is in the gasification plant for providing process steam, cooling, and makeup of wastewater discharges. As discussed in Section 2.2.2, estimation of these water requirements is critically dependent on site

TABLE 2.4-1. COMPARISON OF RESIDUALS AND RESOURCE REQUIREMENTS
 AND RESIDUALS FOR THE MBG AND DF SCENARIOS

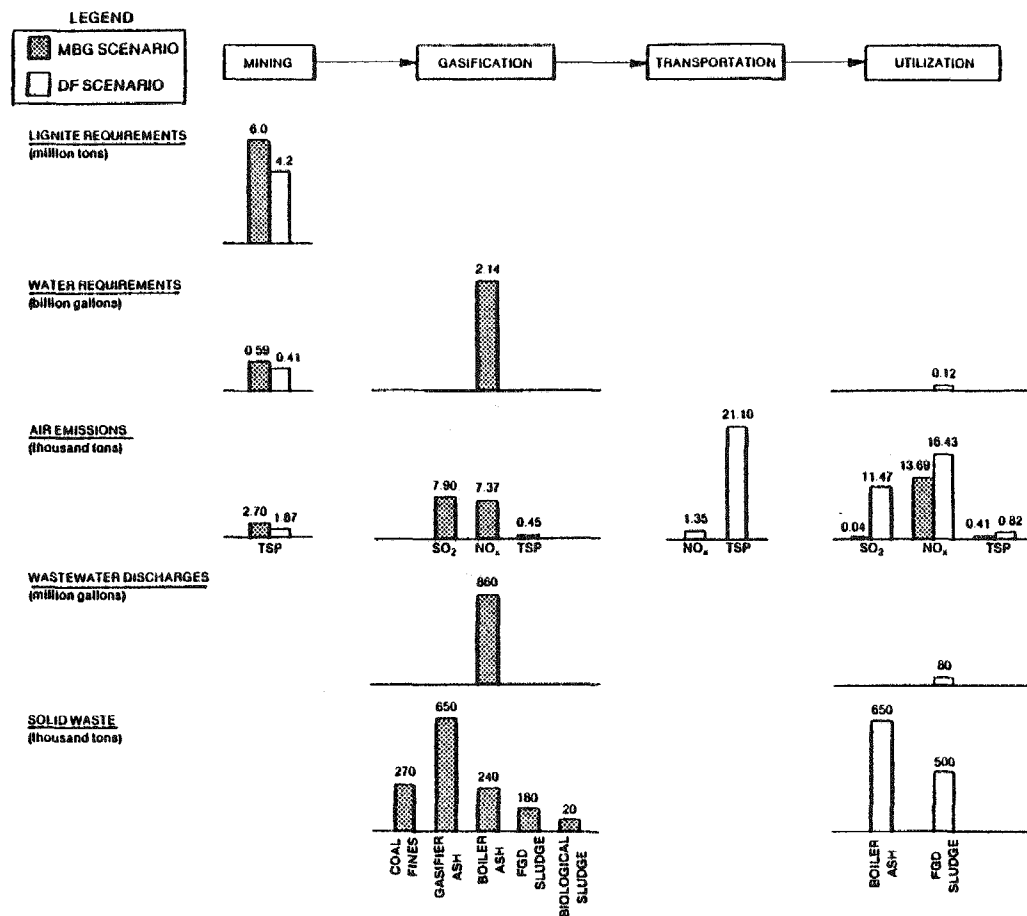
Residual/Resource	MBG Scenario	Direct Firing Scenario
<u>Lignite Requirements</u>	6.0x10 ⁶ tons/yr	4.2x10 ⁶ tons/yr
<u>Water Requirements</u>		
Mine	586x10 ⁶ gal/yr	410x10 ⁶ gal/yr
Gasification	2,140x10 ⁶ gal/yr	0
Utilization [†]	0	120x10 ⁶ gal/yr
<u>Air Emissions</u>		
Mine		
TSP	2,700 tons/yr	1,871 tons/yr
Gasification		
SO _x	7,903 tons/yr	0
NO _x	7,369 tons/yr	0
TSP	447 tons/yr	0
Transportation		
NO _x	0	1,353 tons/yr
CO	intermittent leaks	656 tons/yr
TSP	0	21,102 tons/yr
Utilization		
SO _x	41 tons/yr*	11,466 tons/yr**
NO _x	13,686 tons/yr**	16,425 tons/yr**
TSP	410 tons/yr*	821 tons/yr**
<u>Wastewater Discharges</u>		
Mine	0	0
Gasification	860x10 ⁶ gal/yr	0
Transportation	0	0
Utilization	0	80x10 ⁶ gal/yr***
<u>Solid Wastes</u>		
Mine	0	0
Gasification		
Coal fines	270,000 tons/yr	0
Gasifier ash	650,000 tons/yr	0
Boiler ash	240,000 tons/yr	0
FGD sludge	180,000 tons/yr	0
Biological sludge	20,000 tons/yr	0
Total	1,360,000 tons/yr	0
Transportation	0	0
Utilization		
Boiler ash	0	650,000 tons/yr
FGD sludge	0	500,000 tons/yr
Total	0	1,150,000 tons/yr

[†] Does not include feed water or cooling water requirements.

* Based on EPA Emission Factors.

** Based on NSPS for Electric Utility Boilers.

*** Does not include cooling tower blowdown.



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Figure 2.4-1. Comparison of Resource Requirements and Residuals for the MBG and DF Scenarios

specific considerations and on design requirements related to wastewater treatment and discharge. As a result, the estimated water requirements of 586 million gallons per year may vary significantly in actual plants. Water requirements associated with the MBG scenario mine are also greater than in the direct firing scenario because of the larger mine size.

Water requirements along the Gulf Coast are greater under the direct firing scenario because of water use associated with sulfur dioxide scrubber facilities and bottom ash handling. The analysis does not include water used for cooling or boiler feed makeup which are unaffected by fuel choice. These water uses, depending on specific site and technology considerations, can exceed scrubber and ash handling water demand by a factor of five to ten.

2.4.3 Air Emissions

The major impact of the MBG scenario versus the direct use scenario is to effectively transfer emissions of sulfur dioxide and total suspended particulates (TSP) from the coastal region to the lignite belt. While total sulfur dioxide emissions are decreased by 31 percent in the gasification scenario, emissions in the lignite belt increase from zero to 7,903 tons per year and decrease in the coastal region by 99.6 percent (11,466 tons per year to 41 tons per year). TSP in the direct firing scenario is 570 percent higher than in the MBG scenario. The major cause of this increase is the estimated emission of fugitive dust during transportation of lignite from the mine to the coast. While these emissions will occur over the entire transportation distance, they will tend to be greatest at the rail loading facility and in the first 50 miles of travel. Excluding transportation fugitive dust emissions

(77 percent of the total), TSP emissions under the MBG scenario increase in the lignite belt by 68 percent and decrease in the coastal region by 50 percent as compared to the direct firing scenario.

Nitrogen oxide emissions are also reduced in the coastal region and increased in the lignite belt region under the MBG scenario. The projected 17% reduction in coastal emissions of NO_x is based on compliance with new source performance standards (NSPS) for electric utility firing of lignite and lignite-derived gaseous fuels. Greater reductions in NO_x emissions from MBG firing may be possible depending on the extent of nitrogen compound removal from the fuel. Increased nitrogen oxide emissions in the lignite belt under the MBG scenario result primarily from the combustion of lignite to provide steam and power to the gasification plant.

2.4.4 Wastewater Discharges

A major distinction between the MBG and DF scenarios with regard to wastewater is the location of occurrence. Another major difference is in the total quantity of effluents, with wastewater discharges at the gasification site under the MBG scenario being over 11 times greater than those occurring at the utilization site under the direct firing scenario.

2.4.5 Solid Waste

As with wastewater, the major distinction between the two scenarios with regard to solid wastes is location. In the MBG scenario the discharges of ash and sludge occur at the gasification site while in the direct firing scenario they occur at the combustion site. The composition of these wastes

are similar except for the biological oxidation unit sludge resulting under the MBG scenario. In aggregate, solid waste volumes are 36 percent high under the MBG scenario than in the direct firing scenario.

Footnotes - Chapter 2

¹Kaiser, 1980, p. 3.

²U.S. Environmental Protection Agency, 1977, p. 1.3-2.

³Id., p. 1.4-2.

⁴Kaiser, 1977, p. 342.

⁵Science and Public Policy Program, 1975, p. 1-126.

⁶Delson, J. K. and R. J. Frankel, Residuals Management in the Coal-Energy Industry, Resources for the Future, Washington, D.C., 1974, cited in Rogozen, 1978, p. 88.

⁷Rogozen, 1978, p. 88.

⁸Ellman, 1975, p. 324.

⁹Radian Corporation, 1975, Vol. II, p. 577.

¹⁰Rogozen, 1978, p. B-26.

¹¹U.S. Environmental Protection Agency, 1977, p. 1.7-2 for all emissions except hydrocarbons; p. 1.1-3 for hydrocarbons.



3.0 ENVIRONMENTAL ANALYSIS

3.1 Overview

The objective of Chapter 3 is to evaluate the comparative environmental impacts resulting from siting the technologies described in the medium Btu gasification and direct firing alternatives of Chapter 2. Whereas the emphasis in Chapter 2 is on the estimation of resource commitments and environmental residuals associated with a set of technologies, the emphasis in Chapter 3 is on the identification of environmental impacts and constraints resulting from the emplacement of these technologies at hypothetical sites within the lignite and coastal regions of the state. The importance of this task is in the translation of emissions into site specific, ambient impacts so as to better understand the environmental trade-offs associated with the production and use of MBG versus direct firing of lignite by coastal industry. The hypothetical sites selected for this analysis are in the Brazos River watershed of Central Texas for the lignite mine and gasification facility and in the Galveston Bay area for the industrial boiler.

Section 3.2 of this chapter reviews the existing air, water, land, ecology, and socioeconomic baseline at each hypothetical site. Sections 3.3 and 3.4 evaluate the major implications of the MBG and direct firing scenarios, respectively, on this baseline. Section 3.5 compares the impacts of the two scenarios.

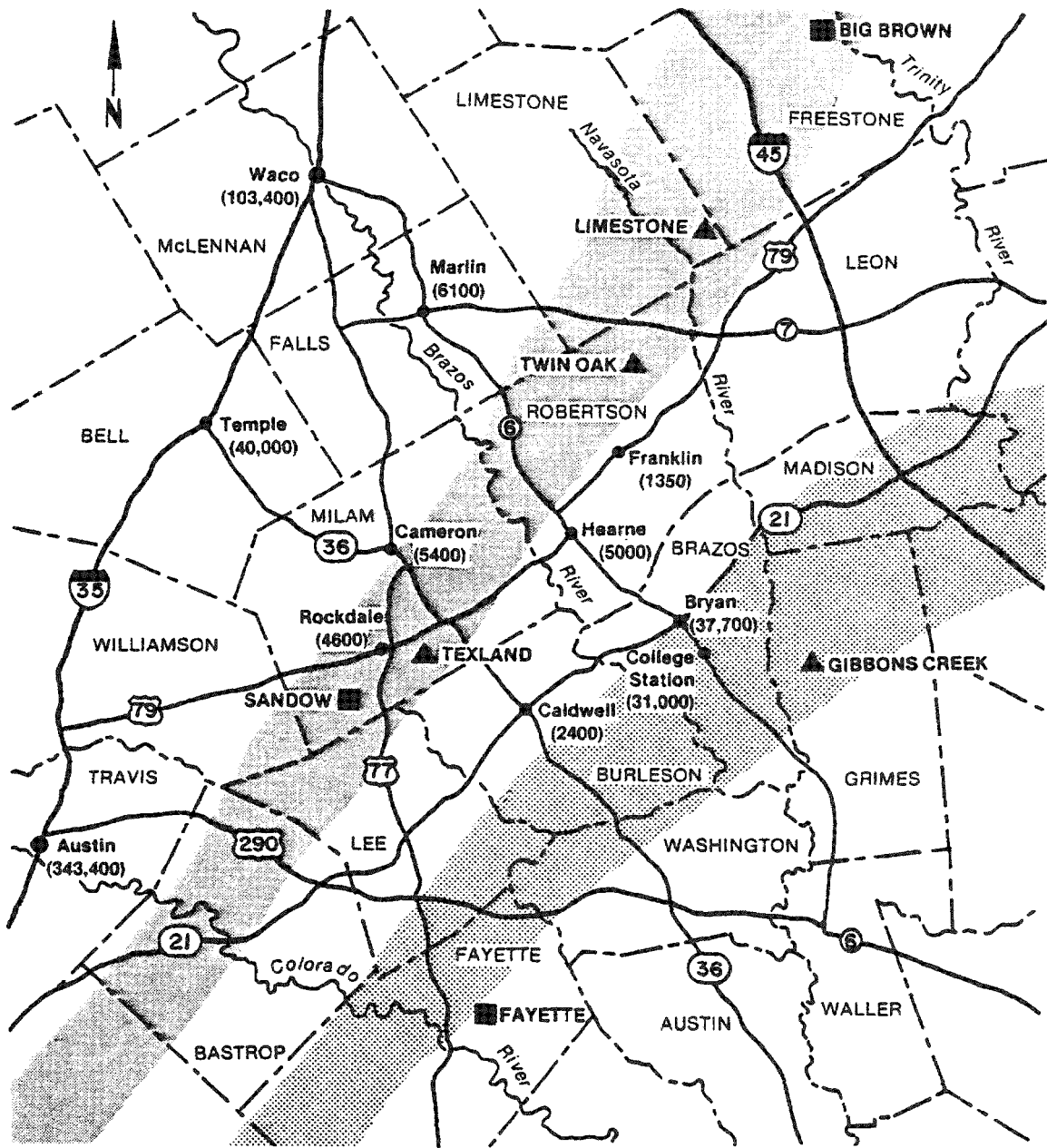
Two facts should be kept in mind in reading Chapter 3. First, the sites selected for analysis, while typical of sites in Central Texas or Galveston Bay, are hypothetical. The development of these hypothetical sites was done by compositing

the characteristics of several individual sites within the region. While similarities between the composite, hypothetical site and actual sites within the respective regions may exist, this analysis is not meant to indicate plans for development of a specific site or project. Second, given the composite, hypothetical nature of the evaluated sites and the complexity involved with detailed analysis of ambient air quality and other environmental media, no detailed computer modeling was done in support of this analysis. As such, conclusions reached should not be taken to reflect a detailed assessment of the hypothetical site as required by regulatory agencies or a statement of the potential impact at an actual site found in the regions of interest.

3.2 Existing Environmental Baseline

3.2.1 Central Texas

Near-surface resources of lignite in Texas occur in two bands stretching from the Rio Grande River northward into Louisiana and Arkansas. Total resources to a depth of 200 feet are estimated at 23,377 million tons. Of this total, 6,431 million tons occur in the Wilcox Group between the Colorado River and the Trinity River shown in Figure 3.2-1. Individual lignite deposits in this central Texas region range in size from 50 to 500 million tons and may be continuous for distances up to 17 miles.¹ Most of the lignites in the Wilcox group occur in the Calvert Bluff Formation. Deposits larger than roughly 250 million tons would be sufficient to support the design gasification plant lignite requirements of 6 million tons per year over a thirty year life (assuming a recovery factor of 85 percent and an unmineable fraction of the deposit of 15 percent).



- Existing Lignite/Coal Fired Power Plant
- ▲ Proposed Lignite/Coal Fired Power Plant
- ▨ Wilcox Group Outcrop
- ▩ Yegua Formation and Jackson Group Outcrop

0 10 20 30 40 50
MILES

C263

Figure 3.2-1. Central Texas Region

For the purpose of this analysis, the hypothetical site shown in Figure 3.2-2 was developed. This site is in a rural area of the Brazos River watershed.

3.2.1.1 Air Quality

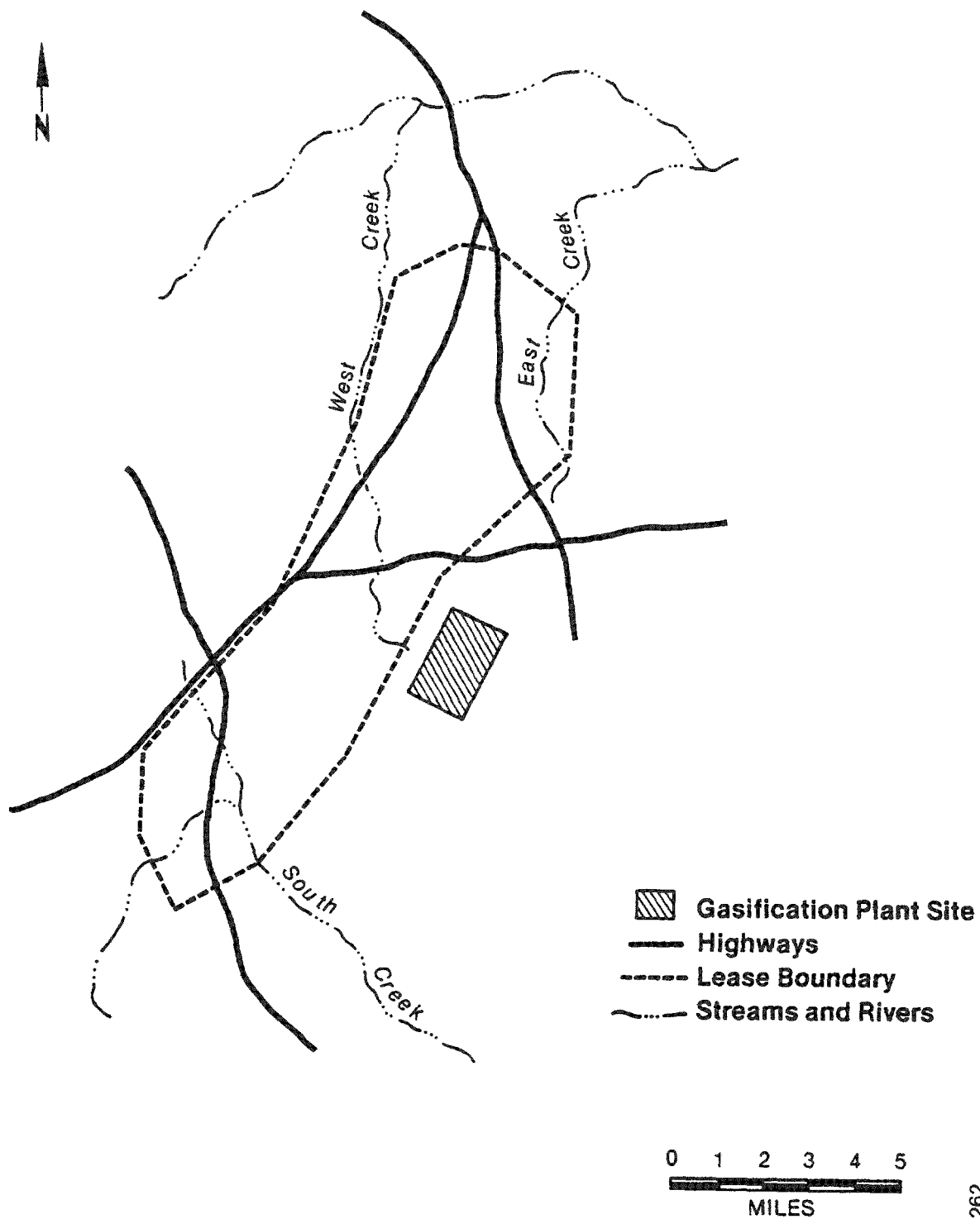
Climate and Meteorology

The winds in this region are predominately from the southeast to south as seen in Figure 3.2-3. The mean direction varies from northerly in the late fall and winter to southeasterly in the spring and summer. The mean scalar wind speed is about 6 miles per hour. The highest average monthly wind speeds occur during the winter when fronts frequently pass through the area. Because of the absence of any nearby terrain feature which could cause major modifications to the atmospheric flow field, plume dispersion in the area is not expected to be significantly altered by local features.

Temperature and precipitation data were obtained for Austin, the nearest major weather station, located approximately 75 miles southwest of the center of the region. The average annual precipitation is 33 inches. Mean monthly temperatures vary from 85° in July and August to 50° in January.

Existing Area Classification

The region is located in the Texas Air Control Board (TACB) Air Quality Control Region 3. The area is designated as a Class II area under the Prevention of Significant Air Quality Deterioration (PSD) sections of the 1977 Amendments to the Clean Air Act. The National Ambient Air Quality Standards (NAAQS) and Class II PSD standards applicable to the region are summarized in Tables 3.2-1 and 3.2-2, respectively.



C262

Figure 3.2-2. Hypothetical Lignite Development Site

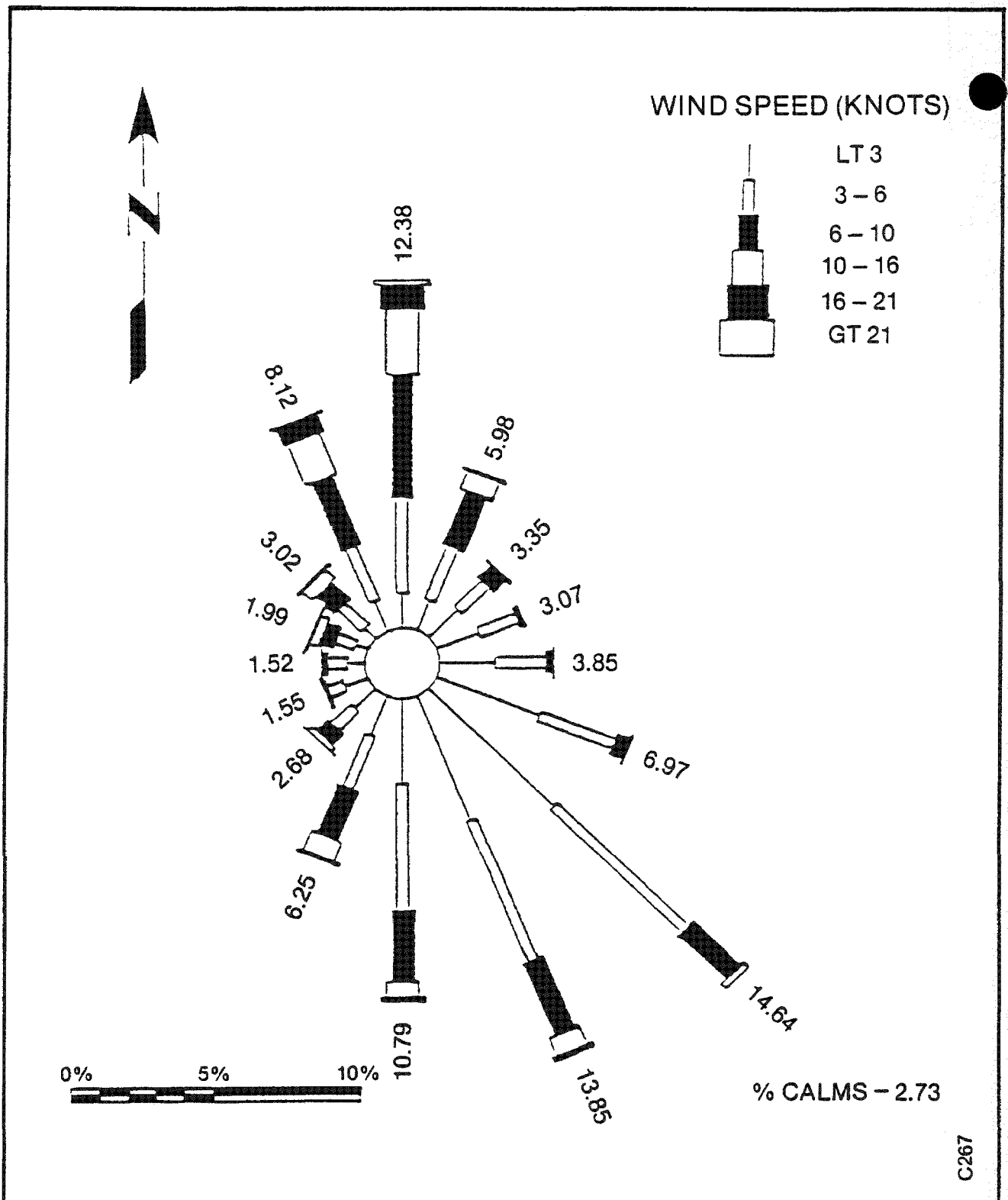


Figure 3.2-3. Wind Rose at the Central Texas Site

TABLE 3.2-1 NATIONAL AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	Federal Primary Standards ¹	Federal Secondary Standards ¹
		$\mu\text{g}/\text{m}^3$	$\mu\text{g}/\text{m}^3$
Sulfur Dioxide (SO ₂)	Annual		
	(Arithmetic)	80	
	24-hour	365	
	3-hour		1,300
Total Suspended Particulate (TSP)	Annual		
	(Geometric)	75	60 ²
	24-hour	260	150
Carbon Monoxide (CO)	8-hour	10,000	10,000
	1-hour	40,000	40,000
Ozone (O ₃)	1-hour	240	240
Non-Methane Hydrocarbons	3-hour (6-9 a.m.)	160 ³	160 ³
Nitrogen Dioxide (NO ₂)	Annual	100	100
Lead	3-month	1.5	-

¹ Title 40 CFR Part 50 National Ambient Air Quality Standards (Standards for averaging times of less than 1 year are not to be exceeded more than once a year).

² As a guide to be used in assessing implementation plans for achieving the annual maximum 24-hour standard.

³ As a guide in devising implementation plans for achieving oxidant standards.

TABLE 3.2-2 PSD CLASS II STANDARDS

Averaging Period	Allowable Increments ($\mu\text{g}/\text{m}^3$)	
	SO_2^1	TSP ¹
Annual	20	19
24-Hour Max. ²	91	37
3-Hour Max. ²	512	none

¹ Pollutants subject to increment analysis as of June 1, 1980.

² Not to be exceeded more than once per year.

The monitoring data presented in Tables 3.2-3 and 3.2-4 are for an actual site in the region and are believed to be representative for rural areas of Central Texas. As discussed below, except for particulate concentrations which appear to be related to "dust storms," none of the measured levels exceed the secondary NAAQS.

The annual geometric mean of total suspended particulates measured between July 1, 1976 and June 30, 1977 was $42.3 \mu\text{g}/\text{m}^3$. This concentration is below the secondary NAAQS of $60 \mu\text{g}/\text{m}^3$ and the primary NAAQS of $75 \mu\text{g}/\text{m}^3$. The highest monthly averages occur during February and March.

The highest daily total suspended particulate (TSP) concentration at the monitoring site, $258 \mu\text{g}/\text{m}^3$, was measured on March 14, 1977. This concentration is 99 percent of the primary NAAQS and exceeds the level of the secondary NAAQS. However, the area is not classified as nonattainment because in order to be so classified, the secondary NAAQS must be

TABLE 3.2-3 AVERAGED MONTHLY AND ANNUAL AIR QUALITY LEVELS AT CENTRAL TEXAS SITE
(JULY 1976 THROUGH JUNE 1977) (Units: Concentrations-Micrograms per
Cubic Meter; Wind Speed-Miles per Hour; Wind Direction-Degrees
Clockwise from North)

	July 1976	Aug 1976	Sep 1976	Oct 1976	Nov 1976	Dec 1976	Jan 1977	Feb 1977	Mar 1977	Apr 1977	May 1977	June 1977	Annual
Nitrogen Oxides	5.5	10.9	4.0	3.4	15.4	40.2	39.2	27.8	21.8	17.2	11.4	8.9	16.6 ¹
Nitric Oxide	4.4	4.4	1.8	1.8	7.2	24.3	22.3	8.2	8.5	6.5	6.2	3.0	3.2 ¹
Nitrogen Dioxide	1.1	6.5	2.2	1.6	8.2	16.0	16.9	19.6	13.3	10.6	6.2	5.9	9.3 ¹
Sulfur Dioxide	8.7	2.9	4.6	7.7	2.4	0.7	2.5	2.5	0.6	1.0	1.2	1.7	2.9 ¹
Total Suspended Particulates	18.6	46.0	56.0	31.0	29.6	31.8	29.8	70.3	105.4	47.5	43.2	49.8	42.3 ²
Wind Speed (Scalar)	4 ³	4	5	6	7	9	7	7	7	6	5	5	6
Wind Direction (Resultant Vectors)	182.4 ³	159.6	83.2	30.4	360.0	344.1	4.2	212.4	141.8	148.6	155.2	162.3	Not Calculated

¹ Arithmetic Mean

² Geometric Mean

³ Based on 8 Days of Data

TABLE 3.2-4. FIVE HIGHEST CONCENTRATIONS OF TSP AND SO₂
AT CENTRAL TEXAS SITE

Pollutant	Concentration ($\mu\text{g}/\text{m}^3$)	Date
TSP (24-Hour Average)	258	3/14/77
	138	2/25/77
	123	3/20/77
	88	5/17/77
	61	3/3/77
SO ₂ (3-Hour Average)	406	9/6/76
	174	1/4/77
	141	10/30/76
	109	7/28/76
	106	10/17/76
SO ₂ (24-Hour Average)	84	9/17/76
	63	9/5/76
	62	10/18/76
	50	9/21/76
	35	9/22/76

exceeded twice per year. The high TSP level measured on March 14, 1977 coincides with reports of blowing dust at the Austin Airport and elsewhere throughout the region.

The second highest 24-hour TSP concentration was $138 \mu\text{g}/\text{m}^3$ on February 25, 1977. This level is below the primary and secondary NAAQS. Blowing dust was reported by the Austin Airport from February 24 to 28, 1977. The $123 \mu\text{g}/\text{m}^3$ particulate concentration measured on March 20, 1977 was also on a day during which the Austin Airport reported blowing dust.

The mean annual nitrogen dioxide (NO_2) concentration of $9.2 \mu\text{g}/\text{m}^3$ at the site is less than ten percent of the primary and secondary NAAQS which is $100 \mu\text{g}/\text{m}^3$. The total nitrogen oxides (NO_x) concentration, composed of NO_2 and nitric oxide (NO), is also much less than the $100 \mu\text{g}/\text{m}^3$ of the NO_2 standard.

The annual mean SO_2 concentration of $2.9 \mu\text{g}/\text{m}^3$ is far below the primary NAAQS of $80 \mu\text{g}/\text{m}^3$. The highest measured 3-hour SO_2 concentration of $405.8 \mu\text{g}/\text{m}^3$ is 31 percent of the secondary NAAQS of $1,300 \mu\text{g}/\text{m}^3$. The other 3-hour SO_2 concentrations measured are less than one-half of the highest measured concentration. The highest measured 24-hour concentration of $8.4 \mu\text{g}/\text{m}^3$ is less than 25 percent of the primary NAAQS of $365 \mu\text{g}/\text{m}^3$. No secondary NAAQS for SO_2 exists for 24-hour or annual averaging times.

Other Air Monitoring Data

The only ambient air monitoring done by the TACB in the urban centers of Central Texas has been at Austin and Bryan, Texas. In general, the measurements taken at these stations are characteristic of urban sites rather than rural areas. All of the monitored ambient concentrations except the TSP concentrations are well below the national primary and secondary air quality standards. The annual TSP standards were exceeded at Bryan. SO₂ and NO₂ levels are presently well below the NAAQS. It is expected that as these urban areas grow, due to secondary growth from lignite development and other sources, the pollutant levels will increase.

3.2.1.2 Geology, Topography, and Soils

The major physiographic province of East Texas is the Gulf Coastal Plain. This coastal plain is underlain by a thick wedge of unconsolidated to poorly consolidated Tertiary strata that are composed chiefly of sand, silt, and clay. In general, these strata dip gently toward the present coastline. The outcrops of these strata on the Gulf Coastal Plain form broad bands that are oldest in the most inland part of the plain. The outcrop bands become progressively younger toward the southeast. The major stratigraphic units become thicker southeastward, so that the entire Tertiary wedge thickens to the southeast both by increasing stratigraphic thickness and by lesser removal of strata by erosion toward the coast.

The hypothetical lignite surface mine is in the outcrop belt of the Eocene Wilcox Group, which is the source of lignite. The Wilcox Group has been divided into three formations in central Texas. These are, in ascending stratigraphic order,

the Hooper, the Simsboro, and the Calvert Bluff Formations. The sediments composing these units were laid down chiefly in fluvial, deltaic, and related depositional environments. The strike of the Wilcox varies across the state but is generally northward, northeastward, and eastward. The dip is to the east, southeast, and south. At the site the regional strike is approximately N 30°E, and the dip is about 2° to 3° to the southeast. Most of the Wilcox is unconsolidated to semiconsolidated.

The hypothetical mine site is in the lignite-bearing lower part of the Calvert Bluff Formation. The contact between the Calvert Bluff and the underlying Simsboro Formation is poorly defined in this area. The Calvert Bluff consists of mixed clay and sand, with the clay strata predominant. The Simsboro is primarily clean sand with a few irregularly interspersed clay beds.

The topography of the study area is gently rolling. The elevation ranges from 370 to 580 feet msl. Slopes over 10 percent are rare. The northern portion drains into East and West Creeks, while the southern portion is drained by South Creek and its tributaries. No major rivers flow through or near the area.

The surface soils of the site area are basically the Uhland alluvial type in the creek floodplains, the Patilo sandy type on some uplands, and the Axtell, Crockett, Demona, Rosanky, Tabor, and Wilson sandy clay type. The fertility is generally low in all of the soils, primarily because of the low nitrogen and very low phosphorus content. Both the liquid and plastic limit are low for the surface horizons and high for subsurface layers. The soil pH ranges from strongly acidic to slightly alkaline. Some soils contain strongly acidic horizons. The

coarse texture and high permeability have caused some leaching into the lower horizons. The average erodibility (K) ranges from 0.17 in the least erodible Patilo and Demona soils to a high of 0.43 in the most erodible Crockett and Wilson soils. Trace element analyses show variable, but generally low values.

Overburden samples show a predominance of silt and clay strata with some sand beds occurring in the Calvert Bluff above the lignite seams. The grain size analyses indicate mostly fine-grained material. Textures vary from sands to clays with mostly clay loams and clays. The erosion potential (K) of the overburden samples varies from 0.10 to 0.70. This indicates that over one-third of the overburden may be moderately to highly erodible.

Overburden geochemical analyses indicate a mildly alkaline condition with considerable calcium carbonate present. This causes a mean (short term) pH of 7.6 which in turn reduces the availability of Mn, Fe, and B, but not of other nutrients. This situation reduces the possibility of iron or manganese phytotoxicity as well as that of other heavy metals, since their solubility is related to pH. The overburden presents no potential salinity or alkali hazard. It appears to contain low concentrations of molybdenum, copper, and possibly boron. Firm estimates of the phytotoxicity of Cd, Se, Hg, Pb, and Ni are not possible; however, the concentrations of these heavy metals do not appear to be high enough to cause problems.

The overburden is low in nitrogen, organic matter, and phosphorus, as are the soils. Potassium is variable, but other nutrients (except Mo and Cu) are abundant.

The mixed overburden is as good as the topsoil for reclamation in most respects. The higher erosion potential of the overburden is the most significant difference anticipated.

3.2.1.3 Surface Water Hydrology

Three main watersheds drain the project area as shown in Figure 3.2-2. The largest stream drains the southern section of the area, flows through a reservoir and eventually into the Brazos River. Two streams drain the north portion of the project area, both draining into a major tributary of the Brazos River.

Most streams within the site are intermittent with the upper reaches of most tributaries being above the water table and, therefore, ephemeral. The only streams exhibiting nearly perennial character are South Creek and the lower portion of East Creek. The average annual runoff for the area is about 4 inches per year, or about 11 percent of the 36 inch average annual rainfall. The average annual runoff generally increases from west to east corresponding to the general trend in annual precipitation totals. The long-term average annual lake evaporation in the area is about 54 inches.

Upstream of the mine boundary, South Creek has a drainage area of 25 square miles. Of this area 9 square miles are already impounded and are normally non-contributing. Additional area drained in and through the mine area totals 30 square miles. Most of the watershed consists of unimproved pastureland. After leaving the mine area, South Creek flows southeasterly for more than 20 miles and flows into a 160,100 acre-foot impoundment, designed for municipal water supply,

flood control, and water conservation. From this reservoir the stream drains into the Brazos River.

West Creek originates in the hills near the central project area and flows north through the area for about 10 miles to its mouth. The drainage area of West Creek is about 50 square miles. The drainage area upstream of the mine area is about two square miles. No significant non-contributing areas exist within this basin. Within the project area the stream watershed consists of mostly pasture, with limited forested and agricultural acreage.

East Creek flows north and drains into the same major tributary to the Brazos River as West Creek. The drainage area of East Creek increases from 4 square miles above the mine boundary to 26 square miles several miles above its mouth. Approximately 11 square miles of the drainage area is within the mine area. Although there are numerous small ponds throughout the basin, these have very little storage volume and essentially all of the watershed contributes to the flow. The East Creek basin is almost entirely natural and consists of mostly pastures and forests with little agricultural acreage.

Flow Characteristics

Streamflow in the Brazos River is greatly influenced by the large number of reservoirs in the basin. The average annual streamflow at the U.S. Geological Survey flow gaging station on the Brazos River at Waco (Station number 08096500) is 2,282 cubic feet per second (cfs). Extremes of flow for the period of record are a low flow of zero in 1918 and a maximum flow of 246,000 cfs in 1936. The calculated seven day average low flow with a recurrence interval of two years (Q_{7-2}) is 82

cfs.³ The Q_{7-2} is the critical flow for assessing water quality impacts and is the flow above which Texas Water Quality Standards apply.

The U.S. Geological Survey records indicate that South Creek is an intermittent stream and that 10 percent of the time there is essentially no flow. Review of the records indicate this normally occurs late in the summer. During low flow periods, this creek begins flowing where seepage from an abandoned quarry located about 700 feet off-stream enters the creek. Continuing downstream, flow is sustained by numerous minor flowing wells and seepages. A major increase in flow occurs at the junction of a major side tributary which receives the sewage discharge from an upstream community's treatment plant. These flows combine to make up the significant portion of low flow in South Creek.

West Creek and East Creek are intermittent with most reaches flowing only after significant rainfall events. There is, however, one reach of West Creek near the downstream boundary of the project area that flows a larger percentage of the time than the remaining reaches. Flow in this reach is best explained by seasonal variations in the water table. That is, the reach is apparently gaining water from ground water during part of the year and losing flow during other parts of the year.

Flood Flows and Floodplains

Flooding within the mine area is not uncommon. Storm events producing precipitation totals in excess of two inches are commonplace. The one-year 24-hour storm event produces 3.3 inches of rain while the ten-year 24-hour storm event produces 6.9 inches of rain.

In addition to the climate, another major factor affecting flooding in the mine area is the cross-section geometry of the stream channels. Most stream cross-sections in the proposed mine area are characterized by a narrow pilot channel and a wide flat floodplain. Most pilot channels not in the headwaters have capacities capable of handling the mean annual flood while the channels in the headwaters generally have adequate capacity for even the most severe storms. Once the capacity of the pilot channel is exceeded the increase in flow is accommodated by the floodplain. The stage of the major flood events generally range from one to five feet above the top elevation of the pilot channels.

Water Quality

Overall water quality in the Brazos River Basin is relatively good, although the entire upper basin is characterized by high dissolved solids due primarily to naturally occurring geological formations. The water quality standards for Segment 1242 (Brazos River from the Navasota River confluence to Whitney Dam) are presented in Table 3.2-5. The total dissolved solids criteria of 1650 mg/l is higher than most segments in the state and reflects the naturally occurring dissolved solids problem in the Brazos River.

The pH of the project area streams range from 6.2 to 7.4. Temperature of the streams show a seasonal and daily fluctuation. Dissolved oxygen (DO) in the streams is generally high; however, during the hot summer months, a DO sag may occur due to the combined effect of high water temperature and

TABLE 3.2-5 WATER QUALITY STANDARDS, SEGMENT 1242 OF THE BRAZOS RIVER

Parameter	Criteria
Chloride (mg/l)	400
Sulfate (mg/l)	250
Total Dissolved Solids (mg/l)	1,650
Dissolved Oxygen (mg/l)	5.0
pH Range	6.5 - 9.0
Fecal Coliform (organisms/100 ml)	200
Temperature °F	95

Source: TDWR, 1979b

increased biological activity. The tributary on South Creek receiving municipal wastewater contributes to low dissolved oxygen levels.

Heavy metals are of concern because of their toxicity to humans, animals, and aquatic life. Concentrations of these constituents in the region are generally below levels recommended for a drinking water supply and for livestock water. Phenols are present in almost all water sampled. South Creek generally has higher concentrations, (average of 3.2 µg/l) probably due to existing development in the basin. Concentrations in East and West Creeks average 1.6 µg/l.

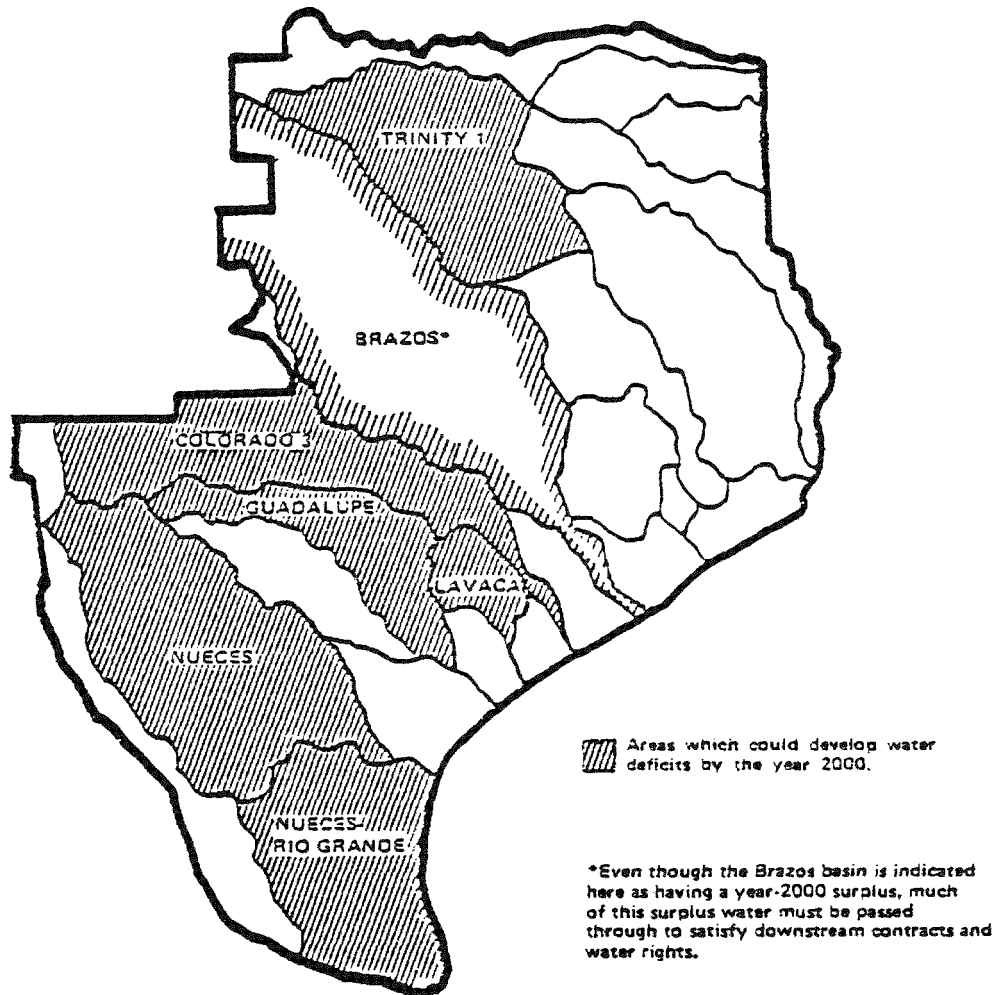
Oil and grease have also been observed in significant amounts in area streams. Average concentrations of oil and grease in the South Creek and East Creek are 22 mg/l and 15 mg/l, respectively.

Species of the nitrogen cycle are generally below a safe concentration level for a drinking water supply and for livestock water. Phosphate is of concern because of its potential to increase eutrophication in downstream lakes. However, the concentrations in area streams are generally below concentrations conducive to eutrophication. Concentrations of chlorides and sulfates are generally within drinking water standards.

Surface Water Users

Most of the water yield of the Brazos River and its major tributaries is under permit to the Brazos River Authority (BRA). According to the BRA, all of its water rights are required for existing and known future uses. Although some excess water is available through the BRA at the present, the availability of water to future users is uncertain. The TDWR has issued some "term" permits usually for 10-year terms, based on the current excess of water allocated. These term permits, however, reflect the opinion that any excess water presently allocated to the BRA will be required for future uses. It is assumed that surface water from the Brazos River will not be available for use by the mine or gasification plant.

The limitation on surface water supply are not unique to the Brazos River. An earlier study⁴ found that depending on the extent to which several proposed new dams are actually constructed, the availability of surface water could constrain energy development in many parts of the lignite belt; critical river basins identified in that study are shown in Figure 3.2-4. As a result, increased use of ground water is likely to be required by new energy developments.



Source: Lacy, 1979

Figure 3.2-4. Year 2000 Critical River Basin Segments

3.2.1.4 Ground Water Hydrology

The Simsboro and Calvert Bluff formations are major aquifers in Central Texas. The hydrogeologic characteristics of these two formations are distinct. Of the two formations, the stratigraphically deeper Simsboro is the more productive aquifer and is of regional importance. The Calvert Bluff is shallower, discontinuous and less productive. The lignite deposits to be mined occur in the Calvert Bluff.

The Simsboro water-bearing sands are from 220 to 520 feet thick in the site area. Most of the recharge occurs in the outcrop area northwest of the study area. Some recharge is also received from the overlying Calvert Bluff formation immediately downdip of the Simsboro outcrop area. When the Simsboro is filled to overflowing, some of the potential recharge is rejected and serves as baseflow in local streams. Further downdip the Simsboro discharges water to the Calvert Bluff by upward leakage.

The water level in the Simsboro varies throughout the site. The water level elevation is about 400 feet msl in the southwestern portion and 340 feet in the northern portion of the site. The hydraulic gradient is about five feet per mile in the northeast direction, and the southeast (downdip) component is about the same. Within the study area the hydraulic conductivity varies between 150 and 350 gal/day/ft². Currently, this aquifer is not extensively used in areas near the site. However, a few large wells do produce water from the Simsboro.

The Calvert Bluff formation is not a major aquifer compared with the Simsboro. However, it is used by some local inhabitants for small supplies. Since the Calvert Bluff formation contains the lignite deposits associated with the site, it will be directly affected by mining. Because of inter-mixed sand and clay units, aquifers in the Calvert Bluff are small and discontinuous. The formation as a whole acts as an aquitard.

Most of the recharge to the Calvert Bluff occurs by infiltration in the upland areas. Much of the upland water is rejected by the aquifer and contributes to the baseflow of the local streams. The ground-water level is highly erratic. No continuous potentiometric surface or flow directions exist. Hydraulic conductivities range from 2.5 to 25 gal/day/ft², but generally are expected to be below 5 gal/day/ft².

The water quality in the Calvert Bluff ranges from fresh to moderately saline. Some areas of the formation contain iron in the form of hydroxides, sulfides, and oxides. This is reflected in the quality of some of the area streams that are fed by discharge from the Calvert Bluff.

3.2.1.5 Ecology

The primary vegetation type at the hypothetical site is Post Oak-Hickory Forest, a mixture of post oak, blackjack oak, and hickory, and is part of a larger zone of oak-and-hickory-dominated forests. Within Texas, this forest type extends northeasterly from Guadalupe County in south central Texas to Bowie County in northeast Texas. Further east in Texas, this forest type may be found mixed with pine and is referred to as the Pine-Oak Ecotone. A total of ten plant assemblages have

been described within the study area. Several of these may be considered as natural assemblages, whereas some have been introduced by man. The Post Oak-Hickory Forest typically occupies the upland, sandy areas of the study area.

Another upland vegetation type, the Mesquite Savannah, consists primarily of mesquite with a grassland groundcover. This vegetation type occurs in areas with a history of overgrazing.

Riparian forest trees found in the region are larger than those of the Post Oak-Hickory Forest. Although areas near rivers were the object of significant clearing activities by the early settlers, many bottomland areas appear to remain in a relatively natural state today. Four different bottomland forest types are recognized, primarily according to floristic composition, although hydrographic and topographic criteria are also thought to differentiate these areas. The bottomland forests occupy only a small percent of the total area; however, they contain the vast majority of large, mature trees and, by far, the largest diversity of tree species.

The other major plant assemblages in the area are grasslands, croplands, roadsides, and aquatic areas. The grasslands consist of two basic types: pastureland/old fields and improved pastures/croplands. Roadsides areas are distinct due to their diversity of invading species. Aquatic areas such as farm ponds and stream pools contain several types of hydrophytic vegetation unique to these aquatic habitats.

Because it is in a transition zone between the eastern forests and the western grasslands, the project area contains animal species from both major vegetation areas. The present

faunal assemblages of this area, and of the entire region, are products of man's intervention during the past 150 years. Since the first settlers began clearing the woodlands, the original natural animal populations have declined. The trend has been away from species such as buffalo and wild horses that once roamed the grasslands and bear, turkey, cougar, and deer that inhabited the dense forests and edges. Fragmentation of the habitats into an alternating pattern of pastures and woodlots has favored those animals that require small areas in which to hide and edges in which to feed. Sparrows, bobwhite quail, flycatchers, cotton-tail rabbits, and small rodents have benefitted the most. No rare or endangered species are known to inhabit areas subject to mining in the region.

Although ten different vegetation associations have been delineated for the area, only six major animal habitat types have been recognized. These roughly correspond to major groupings of the vegetation associations. They are riparian (hardwood bottomland), upland forest (post oak, blackjack oak, Juniperus forest), mesquite savannah, grassland (pasture, old fields), agricultural (cultivated with crops, hay or grasses), and aquatic (farm ponds and streams). These habitats occur in a mosaic pattern with no large areas of any one occurring in the project area. Due to this disaggregation of the major habitats, many of the species normally found in only one habitat type may be found in several in this area. Generally, however, each habitat type can be characterized by several major groups or indicator species.

In comparing the habitat types for their usefulness to the total ecosystem of the project area, the riparian habitat is considered the most important. It permanently harbors more species and also provides cover for many of the

species that feed in other habitats. This habitat type is the most natural of all in the study area and although not truly "unique" on a regional level, could be considered somewhat sensitive on a local scale.

3.2.1.6 Socioeconomics

Population trends indicate continued growth for the Central Texas lignite area. The Brazos Valley Development Council region, for example, grew by 16 percent from 1970 to 1977. Projections indicate another 35 percent increase in this area of Central Texas by the year 2000. Most of the growth is expected to occur in the larger communities and towns of the region. Population of area cities and other basic features are depicted on Figure 3.2-1.

Just over 67 percent of the region's land area is used for agricultural purposes, including cropland, pasture, and rangeland. Much of the area is forested. Agricultural uses are likely to continue into the future, with the major change being brought about in those areas underlain by lignite. Urban uses such as cities, industrial areas, highways, and institutional lands, account for a very small percentage of the land use in the region. While federal lands and water areas comprise an even smaller proportion of the region's land use, there are numerous wetland areas along the Brazos and Navasota Rivers. Lake Somerville between Burleson and Washington Counties is the only large reservoir within the region.

In addition to the urban centers of Waco, Temple, and Bryan-College Station, several small industrial parks are located in the region. Recent increases in manufacturing employment, oil and gas production, and lignite mining have

fostered population and economic growth. Because of a readiness for industrial activities, the region's economy can be expected to continue expanding at a relatively fast pace over the next two decades. As it grows, it should also become more balanced and diversified throughout. Skill levels found in the more rural counties are lower than in the urban areas of Waco and Bryan-College Station. All of the counties in the Brazos Valley are below the state average for family income; much of the area has double the statewide average for families living below the poverty level.

While increased infrastructural capacity will be needed throughout most of the region to accommodate new growth, infrastructure shortages are greatest in Bryan-College Station due mostly to the rapid growth of Texas A&M University and local industry in recent years. Several smaller communities in the Central Texas area have also had problems meeting growth related demands for services. Generally, the smaller a community and the more rapid its growth, the less able it is to meet the increasing demand for services. The Brazos Valley Development Council (BVDC) notes these shortages in its Overall Economic Development Program⁵ as priority problems requiring attention if economic growth is to be sustained. Solid waste disposal, sewer system improvements, parks, water systems, and industrial parks are needs commonly cited for the entire region. In 1970, some 23 percent of the BVDC region's occupied housing was substandard, compared with only 9.2 percent for the state as a whole.

The highway network in Central Texas is well-developed, anchored by Interstate 45 connecting Dallas and Houston and Interstate 35 between Dallas and Austin. Several

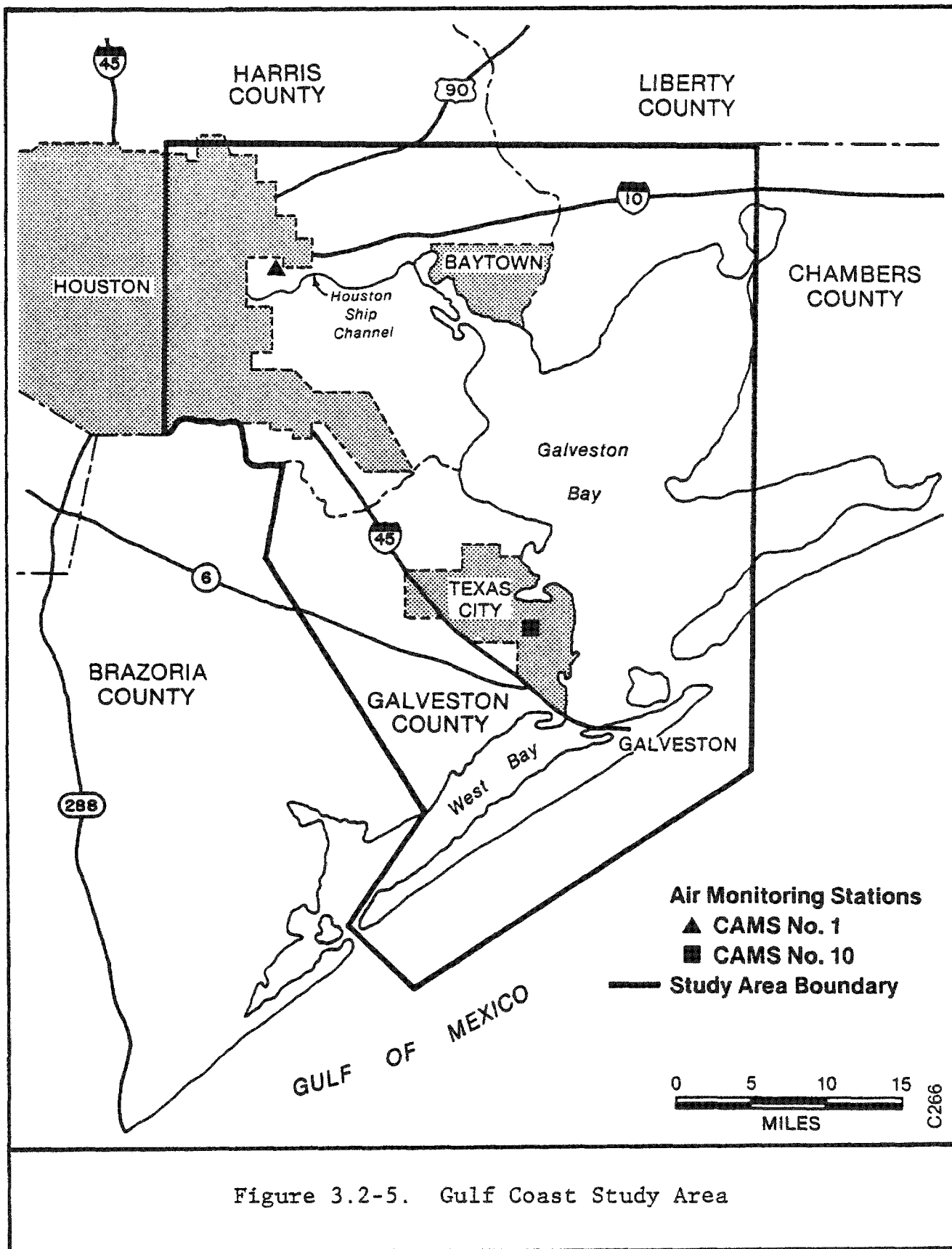
major U.S. highways also span the region. Improvements are in progress in several areas, especially in the Bryan-College Station vicinity. Railroads provide freight service to the area's major communities.

Health care facilities, schools, public safety, and existing utility systems in the Brazos Valley are characteristically just sufficient to meet present demands. Some are slightly over capacity. Large surges of new growth would require construction and personnel development at a rate which most communities would find difficult to meet. Many towns currently rely on other governmental or quasi-public entities (e.g. water supply corporations) to fill the gaps which do exist in services. Health care, in particular, is commonly more available in nearby larger cities.

Scattered cultural resources of historic and archaeological significance have been found in the general area. The presence of such resources in the project area are unknown and would have to be determined based on a future, detailed site survey.

3.2.2 Coastal Texas

The study region used for analysis of the impacts from firing of lignite and MBG includes the heavily industrialized areas along the western edge of Galveston Bay and the Houston Ship Channel. For purposes of analysis, this region consists of all of Galveston County, the western half of Chambers County, and the southeast quadrant of Harris County as shown in Figure 3.2-5. Two major areas of industrial concentration exist within this area--the Houston Ship Channel



and Texas City. In aggregate, these two areas represent an industrial steam demand of approximately 25 million pounds per hour. This equates to a boiler fuel demand of roughly 700 billion Btu per day.

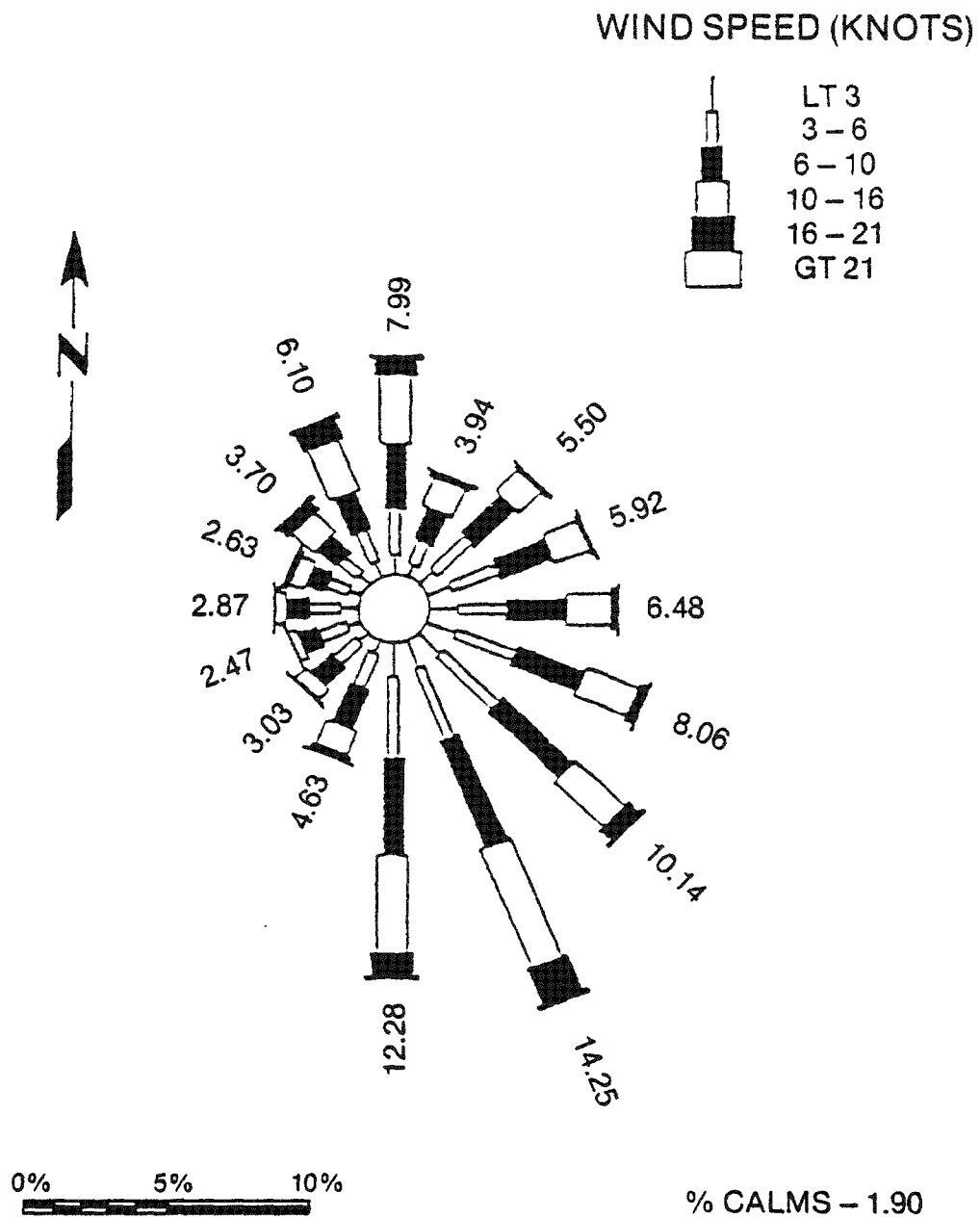
3.2.2.1 Air Quality

Climate and Meteorology

The warm rainy climate of the coastal area is strongly influenced by the Gulf of Mexico and Galveston Bay. Meteorological data at Hobby Airport in Southeast Houston on mean monthly temperatures range from 52°F in January to 84°F in July and August. The average annual precipitation is 48 inches.⁶ The most frequent wind direction is from the south-southeast, and the mean wind speed is about 8 miles per hour. A wind rose for Hobby Airport is presented in Figure 3.2-6. Because of the flat terrain no major modifications to the atmospheric flow or plume dispersion are expected.

Area Classification

The study region is located in the Texas Air Control Board Air Quality Control Region 7 and is a PSD Class II area. Harris and Galveston Counties are nonattainment areas for ozone (O₃). The area surrounding the Houston Ship Channel is classified as a nonattainment area for total suspended particulate (TSP).



C268

Figure 3.2-6. Wind Rose at Hobby Airport, Houston, Texas

Air Quality Monitoring Data

Air quality data used in the analysis is from the TACB's continuous air monitoring station (CAMS) No. 1 located approximately one mile north of the Houston Ship Channel and No. 10 located in a residential area of Texas City. These locations are in Figure 3.2-4. Data for TSP, sulfur dioxide (SO_2), nitrogen dioxide (NO_2), ozone (O_3), and carbon monoxide (CO) are summarized for 1979 in Table 3.2-6.

The annual TSP concentration at the CAMS No. 1 site, $85 \mu\text{g}/\text{m}^3$, exceeded the primary NAAQS by 13 percent. The 24-hour measurement of $159 \mu\text{g}/\text{m}^3$ exceeds the secondary NAAQS of $150 \mu\text{g}/\text{m}^3$. The annual TSP concentration of $54 \mu\text{g}/\text{m}^3$ and the second highest 24-hour concentration of $92 \mu\text{g}/\text{m}^3$ at CAMS No. 10 were both below NAAQS. SO_2 , NO_2 , and CO concentrations at both sites were well below the primary and secondary standards. However, permits issued prior to August 7, 1977 for use of fuel oil as an alternative to natural gas are of serious concern with regard to the SO_2 PSD increment.⁷ Figure 3.2-7 shows the estimated incremental impact on ambient air quality in the Houston-Galveston area that results from use of 0.8 percent oil in these already permitted facilities. The allowable annual increment on SO_2 for a Class II area is $20 \mu\text{g}/\text{m}^3$. Although changes in the basis for computing PSD increment consumption have been made (45 Fed. Reg. 52676) to reflect emissions from facilities which have actually converted to an alternate fuel rather than emissions allowable (but not actually occurring) under existing permits, these modeling results indicate the potential for a significant PSD problem from SO_2 in the Houston-Galveston area.

TABLE 3.2-6. 1979 AMBIENT AIR QUALITY SUMMARY FOR CAMS NO. 1
AND NO. 10 ($\mu\text{g}/\text{m}^3$)

Pollutant	Standard	Measurement		NAAQS	
		CAMS 1	CAMS 10	Primary	Secondary
TSP	Annual ¹	85	54	75	60
	24-hr ²	159	92	260	150
SO ₂	Annual ³	23	33	80	-
	24-hr ²	49	87	365	-
	3-hr ²	162 ⁴	-	-	1,300
NO ₂	Annual ³	69	41	100	100
O ₃	1-hr ²	430	410	235	-
CO	8-hr ²	6,200	2,000	10,000	-
	1-hr ²	9,700	4,300	40,000	-

¹ Geometric Mean

² Second Highest

³ Arithmetic Mean

⁴ 1978 Data

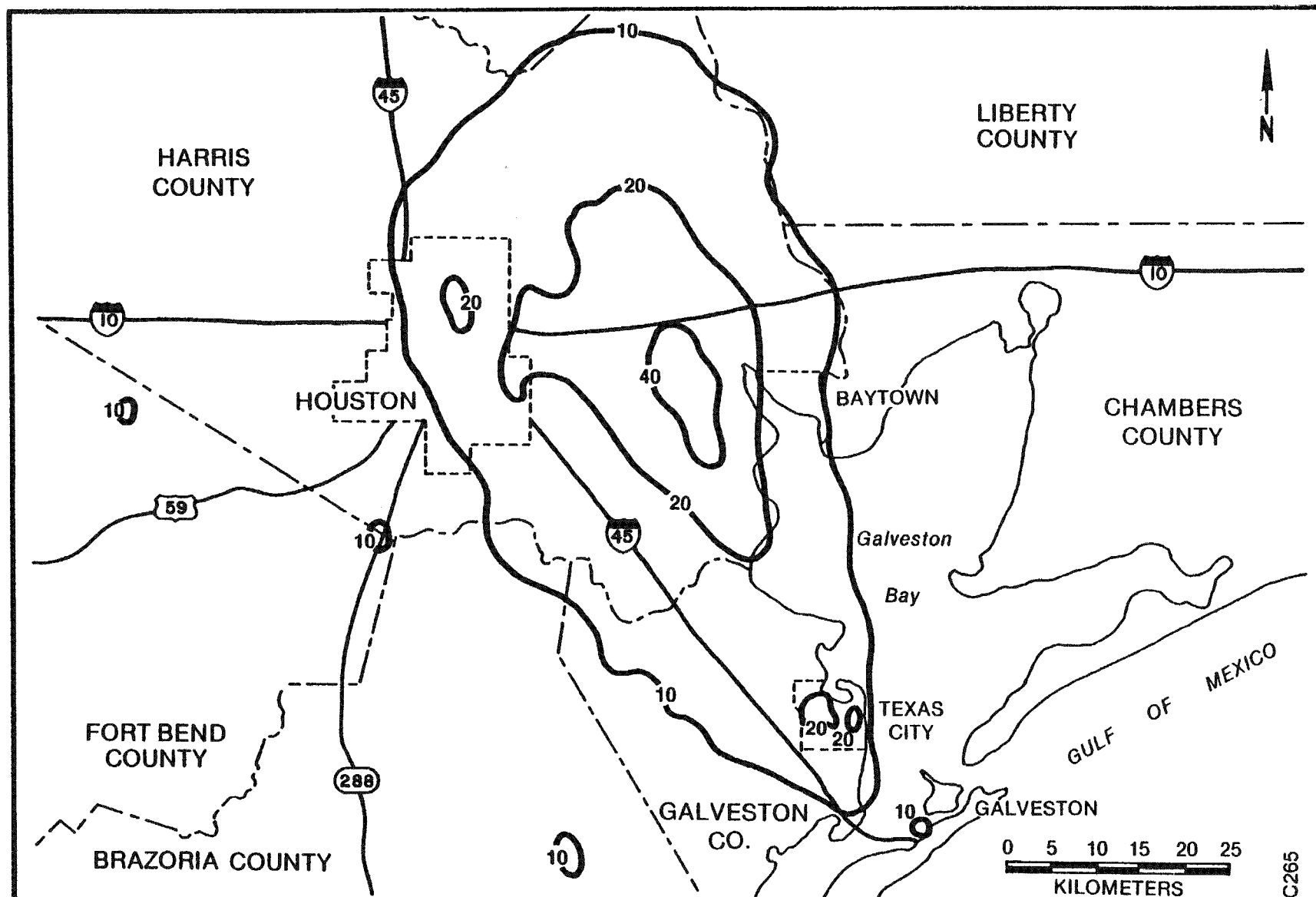


Figure 3.2-7. Estimated Annualized Impact of Existing Permits on the SO_2 PSD Increment ($\mu\text{g}/\text{m}^3$)

Source: Sheffield, 1979

Harris and Galveston Counties are nonattainment areas for ozone. According to TACB SIP regulations, Harris County is an urban nonattainment area. To locate an HC emitting source in Harris County offsets of HC emissions in any ratio greater than 1:1 would be required. In Galveston County, however, because of its classification as a rural nonattainment area (i.e., status due to transport from urban nonattainment area), no offsets would be required.

3.2.2.2 Geology, Topography, and Soils

The substrate in the Houston-Galveston area is primarily comprised of Pleistocene fluvial-deltaic sediments, with Holocene, bay-lagoon marsh and swamp sediments along Galveston Bay to the east and along the lagoon to the south. The fluvial-deltaic sediments are mostly interdistributary muds and distributary sands.

The interdistributary muds consist of locally sandy clay and silt. These sediments have low permeability, unstable slopes, high corrosion potential, high shrink-swell, and low bearing strength. Topography is flat on these muds. These areas are primarily grass prairies and are usually under cultivation.

The distributary sand areas consist of sand and locally clayey sand. These sands have moderate permeability, low corrosion potential, low shrink-swell, and high bearing strength. Topography is flat to rolling. These areas are primarily coastal short grass prairies which are moderately erodible. The sands form shallow aquifers and aquifer recharge areas.

Other minor surface geologic units include alluvial fan and barrier island sands and local gravels, stream meander and beach swale muds, and various muds, silts, sands, and shells.

These surface sediments are underlain by thousands of feet of Cenozoic sand, silt, and clay sediments deposited in many depositional environments. Individual geologic units are briefly discussed in Section 3.2.2.4.

Two notable geologically-related problems in the southern part of this area are subsidence and related tide/hurricane flooding. The area around Texas City, for example, is an area of relatively high and continuing subsidence. Due to groundwater pumping in the area, approximately 8 feet of subsidence has occurred over the past 50 years. As a result, areas to the south and east of Texas City are increasingly susceptible to hurricane flooding.

3.2.2.3 Surface Water Hydrology

All drainage in the study area is ultimately discharged to Galveston Bay. Galveston Bay is the largest bay on the Texas Coast and is considered to be the most important, both economically and ecologically. The Bay is approximately 520 square miles in surface area and includes the Port of Houston, Texas' most important commercial port. The Bay is typical of many of the estuaries along the Gulf Coast, in that it is shallow (average depth of 8 feet) and is nearly separated from the Gulf by barrier islands. The tidal range in the bay is small, one to two feet, and both water levels and currents are greatly influenced by wind. The water level in lower Galveston Bay can be depressed as much as 5 feet below mean low tide by

strong winds in the winter season and raised as much as 15 feet above mean low tide by tropical hurricanes which occur in summer and fall at infrequent intervals.

The Bay provides receiving water for the wastes of the vast urban-industrial complex of the Houston area, and in this capacity has played an important part in the economy and continued growth of the region. The Bay system receives waste discharges from domestic and industrial sources, natural runoff, the Trinity River, San Jacinto River, Buffalo Bayou and the Houston Ship Channel, and various other small tributaries. The major source of industrial waste is the industrial complex located along the Houston Ship Channel above Baytown, estimated to average in excess of 200 million gallons per day. The Texas City Area is the second largest contributor of waste to the Galveston Bay system. In 1968-1969 the flow varied from 115-130 mgd with BOD loadings ranging up to 147,000 lb/day.

Data for Galveston Bay indicated that the water quality was:

- 1) Adequate with respect to dissolved oxygen;
- 2) Relatively stable over the last few years in terms of the biochemical oxygen demand;
- 3) Of deteriorating quality with respect to coliform organisms;
- 4) Essentially enriched and in jeopardy from steadily increasing nutrient levels; and

- 5) In danger of the unknown results of a sustained ecological stress, apparently caused by toxic materials which interfere with the metabolic processes of algae and bacteria.⁸

The commercial fishing industry in Galveston Bay is the most extensive and prolific along the Texas Gulf Coast, both by poundage and value. Furthermore, Galveston Bay hosts a diversity of aquatic life; it is estimated that the Bay is the nursery grounds for approximately 80 percent of the fish species commercially harvested along the Texas Coast.

3.2.2.4 Ground Water Hydrology

Aquifers underlying the Houston-Galveston area have been divided and classified in several ways. The Gulf Coast Aquifer, consisting of Miocene to Holocene sediments, has been defined for the entire Texas Gulf Coast. It includes (in stratigraphic, upward sequence) the Catahoula, Oakville, Lagarto, Goliad, Willis, Lissie, and Beaumont Formations, as well as overlying surficial deposits. The Goliad, Willis, and Lissie Formations are the major sources of groundwater. In the study region, these groundwater units are referred to as the Evangeline Aquifer (Goliad) and Chicot Aquifer (Willis and Lissie).

Regardless of classification systems, about 800-1200 feet of net sand thickness is present above the base of the fresh water zone. The base of the fresh water zone is 2000-3000 feet deep in the Houston area, and rises to a 600-800 foot depth in southern Galveston County. These sands have transmissivities from 200,000 (Houston area) to less than 50,000 (southern Galveston County) gallons per day per square foot (gpd/ft²). Wells yield about 1000 to 3000 gallons per minute (gpm) in the

Houston area, decreasing southward to about 750-1500 gpm in the southern part of Galveston County. Water quality is generally very good (total dissolved solids < 500 ppm), but moderately saline zones are common. In 1960, 400,000 acre-feet/year were pumped for public supply, irrigation, and industrial uses. In several areas, particularly in the Texas City area, water level and artesian pressure declines caused by heavy pumping have caused problems. These problems include land subsidence, surface fault activation, salt-water encroachment, and increased pumping costs. In order to reduce adverse impacts from excessive production of ground water in the area, withdrawals are currently subject to control by the Harris-Galveston Coastal Subsidence District.

3.2.2.5 Ecology

The Galveston Bay Region lies in the northern portion of the Gulf Prairie and Marshes Area, a vegetational province encompassing all of the coast of Texas. Characteristic physiognomic types include grasslands or prairies, woodlands, swamps (especially those bordering rivers and bayous), marshes (fresh, brackish, and salt), and dunes. The majority of the study region is a nearly level plain with less than 50 feet of relief and which is slowly drained by numerous creeks, rivers, bayous, and sloughs. Many of the plant communities in this region have been altered by farming and urbanization.

Prairies of the Galveston Bay Region are characteristically composed of an herb stratum with occasional woody species. Two distinct natural prairie assemblages are recognized; bluestem prairie and coastal or cordgrass prairie. Rice fields and pastures have replaced bluestem prairie in some parts of the region. Various sedges and barnyard grass have

invaded these areas and on the most heavily grazed sites, carpetgrass and smutgrass become conspicuous. Marshes occur along East and West Bay and at the inlet of the Trinity River.

Woodlands in the Galveston Bay Region are characterized by a closed canopy, a loosely defined sub-canopy, and sparse shrub and herb layers. Four assemblages are recognized: 1) cypress swamps of bald cypress, water elm, and buttonbush; 2) hardwood forests of cedar elm, sugarberry, hawthorn, and water oak generally located in the floodplains of major rivers and bayous; 3) upland oak-pine forests characterized by the presence of loblolly pine, sweetgum, willow oak, water oak, and southern red oak occupying generally well-drained upland areas; 4) streamside woodland along smaller waterways composed of willow, sugarberry, hawthorn, water oak, and willow oak.

The main, open water portions of Galveston Bay have little or no submerged aquatic vegetation due to excessive depth, high natural turbidities, recurrent sediment resuspension, and siltation. Nearly all of the submerged vegetation is found in shallow areas and coves with water depths of less than -5 feet mlw. These vegetated areas are characterized by light to moderate stands of shoal grass and widgeon grass. The variable environmental conditions in Galveston Bay, particularly salinity and temperature, restrict the phytoplankton species inhabiting these waters to those that have wide tolerance and capacities for rapid growth and reproduction during periods when conditions are favorable.

The Galveston Bay Region encompasses a number of habitat types, including marine, estuarine, coastal marsh, prairie, and woodland habitats. The area consequently supports

a large number of wildlife species. Many birds overwinter in the area, and many others pass through the area during spring and fall migration. The region is popular with sportsmen as well as birdwatchers. The birds most common in aquatic habitats in the region include herons, egrets, ducks, coots, shorebirds, gulls, and terns. Terrestrial birds likely to occur commonly in the project area include sparrows, blackbirds, warblers, hawks, vultures, crows, and others.

Relatively few mammalian species occur in marine and estuarine areas compared with the number of species which occur in freshwater and terrestrial habitats. Of the marine mammals which occur in Texas waters, only the bottle-nosed dolphin occurs regularly in the Galveston Bay area. Characteristic species of brackish marsh habitats include the northern rice rat, hispid cotton rat, muskrat, nutria, and swamp rabbit. These species also occur in freshwater areas as do the raccoon opossum, Georgia bat, and red bat. The fox squirrel, white-footed mouse, eastern cottontail, and nine-banded armadillo are among the common terrestrial mammals in the area.

Except for the diamondback terrapin, marine and estuarine habitats are seldom used by amphibians and reptiles. Brackish marshes and barrier beaches are inhabited by a few reptiles and amphibians, including the Gulf salt marsh snake, a few turtles, and the Gulf Coast toad. Species typical of freshwater habitats in the area include the smallmouth salamander, cricket frog, bullfrog, southern leopard frog, red-eared slider, diamondback water snake, and western cottonmouth. Characteristic terrestrial amphibians and reptiles within the project area include Gulf Coast toad, gray treefrog, three-toed box turtle, green anole, northern fence

lizard, Texas rat snake, eastern garter snake, southern copperhead, and western diamondback rattlesnake.

The Galveston Bay system, including contiguous wetlands and tributaries, provides highly productive nursery areas for numerous marine and estuarine fish species. The distribution and abundance of the fish species of Galveston Bay change due to a number of factors. Salinity changes due to the level of freshwater runoff into the bays can alter the species distribution drastically. However, a number of reasonably predictable cycles correlated with reproduction and subsequent growth and maturation of the spawn occur yearly. The system supports substantial sport and commercial fishing. These, and other factors, combine to make the Galveston Bay system one of the most important estuaries on the Gulf Coast.

Although most benthic organisms have little or no direct economic importance, their value in the food chain is considerable. Common benthic organisms in the Galveston Bay Region include polychaetes, molluscs, crustaceans, and in areas of low salinity, insect larvae. From a commercial and perhaps ecological viewpoint, the oyster constitutes the most important benthic organism in the Bay system.

The areas generally considered prime nursery habitat for Galveston Bay include much of the southern shoreline of East Bay, the majority of the eastern shoreline of Trinity Bay, the upper corner of Trinity Bay at the mouth of the Trinity River, the Cedar Bayou area, and Clear, Dollar, and Moses Lakes. Any marshes associated with these areas would be included in the nursery areas.

A number of threatened, endangered, and peripheral animal species may occur in the proposed project area including the Brown Pelican, Northern Bald Eagle, Southern Bald Eagle, Arctic Peregrine Falcon, and American alligator. There are no known listed or proposed threatened or endangered plant species in this area. Also, there are no listed or potential National Natural Landmarks in this area.

3.2.2.6 Socioeconomics

Industrial growth in the study area, related primarily to the petrochemical industry, has caused a large and rapid increase in population for at least the past two decades. The Houston metropolitan area already contains well over 2 million people. Average growth rates in recent years approach three percent annually. Trends point to a continuation of growth through the year 2000.

New infrastructure is being put into place regularly to support this rapid growth. When shortages in housing or public services occur, it is generally temporary because local governments in the region have customarily supported industrialization and population growth for many years. The Houston-Galveston area represents nearly one-fourth of the total state demand for new housing. Land use trends away from agriculture and toward suburban and urban uses are expected to continue.

The economy in this large and fast-growing area of Texas is increasingly diverse, though still dominated by the petrochemical industry. Jobs in the services and trade sectors have grown to equal or exceed the actual number of jobs in manufacturing. Agricultural employment and land use have all

but disappeared from the Houston-Galveston area, having given way to the pressures of urban growth needs. Unemployment, while usually below the statewide average (recently running at around 6 percent), nevertheless translates into rather substantial numbers. For Harris and Galveston Counties alone, between 65,000 and 70,000 workers may be unemployed at any one time. Skill levels of the work force are higher for these counties than for those of rural Central Texas, due to the more diversified urban economy.

Per capita income in the Houston-Galveston area also exceeds the statewide average. Harris County in 1975 (at \$5815) was almost 25 percent above the statewide average per capita income (\$4661). The area has a lower percentage of poverty than either the state as a whole or rural counties in particular. Again, this reflects the influence of a large and expanding metropolitan economy.

The transportation system, typical of that found in southern and southwestern cities, is dominated by the automobile. Extensive freeway systems connected to Interstate and U.S. highways have been rapidly built in an attempt to keep pace with suburban expansion.

The Houston-Galveston area contains some of the best health care systems in the state, thanks in part to the presence of university-affiliated facilities. Moreover, it offers a full range of general and specialty services simply because there is ample population to create a demand.

Recreation opportunities are best for "developed" uses rather than natural setting experiences. Urban-industrial land uses are too widespread over most of the region to leave

much in the way of natural resource-based recreation, with the occasional exception of fishing in coastal areas. Beach activities are still popular.

3.3 Major Gasification Impacts

3.3.1 Central Texas

3.3.1.1 Air Impacts

Lignite Mine

As discussed in Section 2.2.1.2, the major air emission associated with surface mining is fugitive dust from the mine, haul roads, and storage areas. These emissions are presented in Table 3.3-1. Because fugitive dust emissions from mining activities are not considered in the determination of a source's potential to emit under current PSD regulations, a PSD permit for the mine will not be required. However, these emissions must be included as a secondary source in PSD modeling for the gasification facility. In such cases, extensive dust control efforts may be necessary to meet PSD requirements. Emissions of other pollutants--NO_x, CO, SO₂, O₃, and HC--are not expected to be significant.

Most particulates will be deposited very close to the mining activities due to their low release height and gravitational fallout. While high particulate levels may occur in the immediate vicinity of the mine, it is expected that particulate levels will decrease to relatively low levels within about 2 miles of the mining activities. Whether levels in excess of the Class II PSD increment will occur outside of

TABLE 3.3-1. FUGITIVE EMISSIONS FROM A 6.0 MTPY SURFACE MINE*

Process	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Controlled Emissions (tpy)
Haul Roads	1820-8500	85	270-1275
Overburden Removal	470-2775	-	470-2755
Stockpile Erosion	610	50	305

*The ranges reflect differences in mine depth, distances to storage facilities and other factors which will vary with time.

the mine area will depend upon the location of mining activities with respect to alignment with prevailing winds and other activities and to the borders of the mine area. A detailed air dispersion modeling analysis of particulate emissions would need to be performed to determine if any violations of the Class II increment will occur outside the mine area.

No applicable TACB regulations exist for comparison with these particulate emissions. TACB Regulation I, 131.03.04.001 "Particulate Matter from Materials Handling, Construction and Roads" apply only in Standard Metropolitan Statistical Areas where the Federal air quality standards for particulate matter are exceeded. As indicated previously in Section 3.2.1.1, existing air quality in the mine area is in attainment of the primary and secondary standards for particulate matter.

Gasification Plant

The proposed gasification plant will be subject to air quality restrictions imposed by TACB construction and operating requirements and by regulations administered by EPA for PSD. The EPA-administered PSD regulations will probably impose the greatest restrictions, both on allowable emissions from the project and on allowable ground level pollutant concentrations. Therefore, this air quality analysis will focus on the impacts of the PSD regulations on the design and operation of the gasification plant for the pollutants regulated by PSD, and on the impacts of the NAAQS regulations for those pollutants not covered by PSD. The emissions listed in Table 3.3-2 are based upon a feed rate of 20,000 tons per day of lignite to the plant and are a composite of Tables 2.2-8 and 2.2-9.

No adverse short- or long-term impacts on the TSP standards are expected from the gasification plant. The gasification of lignite results in relatively low emissions of TSP. Emissions from the on-site boiler system will be limited to utility NSPS levels--0.03 lb/million Btu of heat input. Additionally, the boiler stacks which emit the majority of pollutants from the gasification plant would be relatively tall (300 to 800 feet) to promote pollutant dispersion. Therefore, it is expected that stack emissions of TSP from the gasification plant would result in relatively small increases in ambient TSP levels. Excluding the naturally occurring dust storms in Central Texas discussed in Section 3.2.1.1, there do not appear to be any problems with respect to the TSP NAAQS or TSP increment consumption.

TABLE 3.3-2. ESTIMATED EMISSIONS FROM THE LIGNITE GASIFICATION PLANT

Pollutant	Emissions (Tons/Yr)
TSP	447
SO ₂	7,903
NO _x	7,369

The gasification plant has large estimated SO₂ emissions, 7,903 tons/year, as shown in Table 3.3-2. However, it is not expected that the emissions are sufficient by themselves to totally consume the SO₂ PSD increment in areas near the plant. However, given the prior development of several lignite-fired electricity generating plants in the area (see Figure 3.2-1), the entire PSD increment for SO₂ may not be available at some specific locations. The siting constraints posed for lignite development by PSD limitations on SO₂ are of potentially major importance in many areas of the lignite belt.⁹ A more definite picture of SO₂ increment consumption could be obtained through modeling. In addition, though the gasification plant has large SO₂ emissions, the height of the stack emitting the SO₂ allows for enhanced dispersion. Because of low background SO₂ levels in the area, it is doubtful that there would be any ambient concentrations above the SO₂ NAAQS.

No adverse short- or long-term impacts are expected from the NO_x emitted by the gasification plant. Due to the enhanced dispersion from tall stacks and the isolated location of the site with respect to major NO_x sources, the resultant NO_x ground level concentrations should be well below the ambient concentrations regulated by NAAQS.

Emissions of CO and O₃ can be considered negligible. Hydrocarbon (HC) emissions were not evaluated because of inadequate process data.

3.3.1.2 Geology, Topography, and Soils

In projecting the impacts on land resources, the shallow substrate (soils) and deep substrate (overburden) are involved jointly in the impact analysis. Consequently, these two aspects, which were described separately in Section 3.2.1.2, will be discussed simultaneously in this section.

Lignite Mine

The strip-mining process will alter the physical, chemical, and biological properties of the substrate through the depth of mining. The major properties that can change are texture, structure, pH, water-holding capacity, cation exchange capacity, concentrations of chemical constituents, organic matter content, microorganisms, bulk density, and derivative properties. The major significance of these properties relate to their potential effect on plant growth in the reclamation phase. Another significant aspect of these changes is the effect on surface water and ground water. The substrate character will determine runoff rates and consequently suspended and dissolved solids contents in downstream areas.

During the process of stripping, spoil piling, and final replacement, overburden materials will become thoroughly mixed. With the exception of the interburden material which is generally higher in sulfur and other undesirable materials, no strata are expected to be consistently inferior or superior to other strata as mineral parent material for soils. Assuming proper disposal of interburden and of strata immediately adjacent to lignites, the mixing of remaining overburden material appears to present no insurmountable problems to successful reclamation. Readily available nitrogen, phosphorus, micro-nutrients and convertible organic matter are variably deficient throughout the section and generally will require treatment for successful revegetation. Because of the variability in the overburden characteristics, an initial liming and fertilization of the soil may be required to ensure uniform revegetation.

Another impact on land resources is the temporary, increased susceptibility to erosion and soil loss. Of the projected 1,200 acres that would be disturbed at any given point in time, usually about one-half that amount is especially subject to erosion unless properly managed. Erosion management of the disturbed overburden will be required as an integral part of the reclamation plan. Rolling land surfaces (less than 20 percent slopes) will minimize erosion. A surface water drainage system must be adequately designed to divert water away from the active area and prevent transport of eroded sediments off-site. Sediment retention structures will serve as interim measures. A vegetative cover of natural and introduced grasses will provide permanent erosion and sediment control.

Successful reclamation to rangeland and, in some areas, improved pastureland can result ultimately in better land productivity than now exists. Assuming the topography is

returned to premining conditions and vegetation is established (as required by existing state rules), direct long-term impacts to land resources are economically positive. Only in the short term are any adverse impacts likely to be realized (e.g., soil destruction, temporarily and locally poor substrates, and increased erosion).

Gasification Plant

The impacts on the geology, topology, and soils of the area resulting from the gasification facility will primarily result from land use associated with the plant site and waste disposal facilities. The plant site represents a total of 1500 acres, including buffer zones. Impacts such as removal and loss of soil, and alteration of topography are expected to be localized and relatively minor. No geologic hazards such as active faults are known in the area. Properties of the substrates such as foundation strength, shrink-swell potential, slope stability, and corrosivity should be considered in plant design but are not expected to represent a significant environmental consideration.

The impacts from solid waste disposal will depend on the type of waste disposal facility. Depending upon design considerations, ash and FGD sludge may be disposed of either in the mine or in a surface disposal facility. Over the 30 year operating life of the plant, ash and FGD sludge will represent a total volume of approximately 15,000 acre-feet. Assuming surface disposal to a depth of 30 feet, this equates to 500 acres or roughly eight-tenths of a square mile. The biological sludge from the gasification wastewater treatment facility is expected to require surface disposal. The total volume of this

material over the life of the plant is approximately 1400 acre-feet; acreage requirements will depend on the method of disposal such as landfilling or land farming.

3.3.1.3 Surface Water Hydrology

Lignite Mine

During the mining operations many small stream channels would be relocated and runoff diverted from the mine area by temporary berms and channels. Temporary diversion channels should be designed to handle 10-year, 24-hour rainfall while at the same time have low enough flow velocities to minimize erosion. Permanent diversion channels must be designed to handle the 100-year storm event.

The major impacts on surface water from the lignite mining operations results from changes in terrain due to mining and construction of settling ponds to contain and treat runoff. Because of changes in terrain, existing creek channel slopes are likely to increase, resulting in higher flow velocities and increases in erosion. To minimize these impacts, re-establishment of vegetation and meandering channel patterns should be used. Drainage divides should also be re-established to match pre-mining conditions in order to minimize flooding from increases in drainage area of individual streams. Settling ponds decrease the normal contributing flow to downstream segments and reduce peak flow rates. On the other hand, settling ponds can also increase the quantity and duration of low flow downstream of these ponds. Most of the water flowing into these ponds would be used in the mine area for dust control.

The quality of water discharged from settling ponds is described in Table 2.2-1. At the given regulated concentration, these pollutants should not cause significant problems in the receiving streams. Although not included in the list of regulated parameters, total dissolved solids (TDS) are also a concern associated with surface mining. While mining in the study area would increase TDS loads, mining is not expected to significantly increase concentrations in major streams outside the lease area.

Gasification Plant

Surface water impacts from the gasification plant include increased storm-water runoff volumes due to construction of impervious ground cover and water quality impacts from coal pile and site runoff and from wastewater discharges. As discussed in Section 3.2.1.3, ground water will be used for consumptive needs in the plant such that surface water use impacts are not a consideration. Sedimentation/detention ponds (including treatment processes such as sand filters) should be adequate to effectively mitigate both runoff quality and quantity problems.

Wastewater from the gasification plant consists of an inorganic stream from the reverse osmosis unit and an organic stream from the gas cleanup facilities. The inorganic stream is a brine contaminated with dissolved solids (3,000 to 4,000 mg/l). Depending on design stream flows and discharge limitations, additional ground water flows could be required for inorganic brine dilution prior to discharge to surface waters. Design characteristics of the organic discharge are presented in Tables 2.2-7 and 2.2-12. Assuming wastewater

treatment facilities operate as designed, these discharges should not be a major constraint to plant siting. Because of limited operating experience with wastewater treatment facilities as described in Chapter 2, the actual effluent quality from these systems is an area of uncertainty.

3.3.1.4 Ground Water Hydrology

Lignite Mine

Several types of primary impacts on ground-water systems can occur as the result of surface mining the lignite. These impacts can be classified into three categories as follows:

- Changes in the physical properties (aquifer characteristics) of the systems;
- Changes in the quantity of water contained in the aquifer systems; and
- Changes in the quality of ground water contained in the aquifer systems.

The greatest potential impacts on the physical properties of aquifers resulting from area strip mining are changes in porosity, permeability, and ground-water storage characteristics of the Calvert Bluff. As noted in Section 3.2.1.4, the Calvert Bluff is not presently a major source of water supply due to the presence of the more productive Simsboro aquifer at only slightly greater depths.

The only appreciable ground-water supply impact expected is the lowering of water levels in the Calvert Bluff Formation in the areas peripheral to an active mine site. Only the Calvert Bluff aquifers will be affected; the Simsboro is at sufficient depth below the bottom of the mine to preclude major water supply impacts on that aquifer. Although initial dewatering may be required before excavation of the initial box cut, aquifer pumping will be temporary. The major ground-water "losses" will be from drainage of aquifers through the mine walls. The distance over which lowering of water levels will occur depends on the depth to the water table in comparison with the mine depth, aquifer permeability, and other physical parameters. Assuming a mine depth of 250 feet, a ground-water depth of 50 feet and typical aquifer characteristics, the water table would be lowered about 20 feet at a distance of 1,000 feet from the mine. With this amount of lowering of the water table, it may be necessary to deepen or redrill some of the Calvert Bluff wells that are within a mile of the mine. A systematic monitoring program of active shallow wells near the mine should be instituted as mining proceeds so that affected wells can be deepened or alternate water supplies developed before undue inconvenience occurs to existing well owners.

The impacts on ground-water quality from lignite mining constitute an area of environmental concern. Because the mining will take place in the Calvert Bluff Formation, the Calvert Bluff aquifers will be most directly affected. The Simsboro aquifer, where it underlies the mine area, could also be affected by degraded recharge from the Calvert Bluff.

The extent of ground-water quality degradation in the Calvert Bluff is not fully known, but is expected to depend on the percent sand and geochemistry of the mined overburden.

Except in conditions where the sand percent is relatively high, the permeability of the reclaimed spoil is expected to be lower than existed prior to mining.¹⁰ Given the generally high clay content of the overburden in the hypothetical mine, the reclaimed spoil is expected to form a partial barrier to the movement of groundwater. Rainfall and other sources of recharge are likely to either be rejected from the aquifer and result in increased surface-water flow or be rerouted through unmined portions of the Calvert Bluff and/or high-sand conduits in the reclaimed spoil. Given the uncertainty in the fate of recharge water flows and concern over potential degradation of groundwater quality, the following analysis assumes that groundwater movement through the reclaimed spoil does occur.

Generally speaking, water infiltrating the Calvert Bluff spoil areas will be degraded in quality as it moves through the geohydrologic system. This degradation will vary spatially and cannot be completely described without a large data base. Consequently, this analysis is based on average conditions over the study area, as determined by aggregating overburden geochemical data. Because flow through the spoils will encounter a variety of materials, water quality changes may tend to exhibit an "averaging out" process. This fact suggests that taking an aggregated approach may not seriously overstate or understate actual effects.

Based on the geochemical data from overburden samples, the water quality of the saturated zone of the mixed spoils will be slightly saline. Calcium will likely be the dominant cation. Due to naturally occurring attenuation mechanisms, the movement of water and release of contaminants from disturbed overburden are likely to be slow. However, because distribution coefficients (which quantitatively describe the partitioning of a

chemical species between the solid and liquid phases) are not known for these materials, the speed of movement of any contamination plume cannot be quantified. Cation exchange capacities are relatively high, which indicates the clays will sorb heavy metals effectively. While some increase in TDS concentrations is likely to occur, it is expected that water quality in unmined portions of the Calvert Bluff will not be significantly different than that which exists naturally in the study area.

There is also a component of ground-water flow downward across bedding between the Calvert Bluff and Simsboro formations. Thus, contaminated ground water that is generated in the lignite mine or overburden and flows out of the mine could eventually contribute to recharge water to the Simsboro. However, the rate of ground-water flow across bedding is generally much slower than parallel to bedding. The rate of downward flow is probably less than 0.5 feet per year. The occurrence of the stratigraphically lowest lignite in most parts of the study area is generally more than 100 feet above the top of the Simsboro. Thus, more than 200 years would be required for contaminants to migrate 100 feet downward toward the Simsboro. The attenuation effect of clay on trace elements will further enhance ground water flowing across bedding.

Gasification Plant

Withdrawal of 5,000 gpm of ground water from the Simsboro and/or Calvert Bluff aquifers for use at the gasification plant will be necessary. Although these ground water withdrawals are relatively high, existing data indicate that it can be met without adverse impacts. Well yields up to 2500 gpm are possible in this area, and properly designed well

fields may yield up to 12,500 gpm. This pumping will locally reduce ground-water availability to other nearby users. However, the excellent aquifer properties of the Simsboro Sand, the proximity to the recharge area, the relatively small amount of water required vis a vis that which is potentially available, and the ability to scatter the location and operation of withdrawal points will effectively reduce the adverse effects of such ground-water usage to a negligible concern.

Ground-water quality near the site may be affected by gasifier ash, boiler ash, and sludge solid waste disposal if disposal sites are not properly designed and operated. In such instances, the preceding statements concerning pollutant attenuation, ground water movement, and aquifer water supply value are applicable to these potential impacts. An estimated 1.36 million tons per year of waste will be generated. Unused coal fines can be disposed of in the mining pit. Over a 30 year operating life for the plant, ash and FGD sludge wastes will total approximately 31 million tons. Although ashes and FGD sludge are a relatively low-risk waste, their large quantity raises the possibility of relatively high waste loadings on a local ground-water system. The biological sludge from the gas treatment wastewater stream may be ruled a hazardous waste under the Resource Conservation and Recovery Act of 1976 and thus could have to comply with more substantial disposal requirements.

The secondary impacts of the lignite mine activity on ground-water resources are related primarily to the increase in population that will result from the economic stimulus of the mine and gasification plant development. The most important impacts are the increased withdrawal of ground water to meet the needs of the additional population and the potential

ground-water quality degradation resulting from such added pollution sources as additional septic tanks and increased solid waste that must be disposed.

3.3.1.5 Ecology

The mining and gasification activities that have the potential for directly affecting the biota of the project area are stormwater runoff, mine dewatering effluents, gasification plant wastewater, noise from facilities and equipment, blowing dust from mining activities and from spoil, storage and waste piles, land clearing, and the type of reclamation after mining. Since various control measures will be incorporated into the mining and gasification processes, not all of these activities will result in adverse impacts on the area's ecosystem.

Land clearing and post-mining reclamation practices will have the largest adverse effects on the biologic communities of the study area. The basic mining scenario consists of 375 acres per year being cleared, mined, and initially revegetated to pastureland. Approximately 1,200 acres will be disturbed at any one time including haul roads and processing facilities which will be minimal in areal extent. The gasification facility, although occupying a total area of 1,500 acres, will destroy the wildlife habitat on only the portion of the area where construction of facilities, coal storage, and other major changes in surface use occur. This area is estimated at 400 acres. The remaining 1,100 acres consists of buffer zones and other areas which are excluded from alternate land uses, but will not be eliminated as habitat for many smaller species. Additional ecological impact will also occur should a new reservoir be required to provide water to the plant for cooling and other needs.

It is assumed that stormwater runoff and possible seepage water from mined areas will be collected in sedimentation ponds and allowed to settle prior to release into area streams. Presently it is anticipated that there will be no sedimentation pond discharge; however, should there be a discharge, treatment will be required to assure that effluent quality is sufficient to protect the biota of the area. As discussed in Sections 2.2.2.2 and 3.3.1.3, uncertainty exists with regard to the quality of gasification facility wastewater discharges. TDS, toxic organics, and trace metal contents of these wastewater streams are of particular concern.

Noise from mining and related processing will have an effect on the biota of the immediate area; however it is not expected to significantly affect animals beyond the immediate vicinity of the equipment. No species of animal that is very sensitive to noise currently resides in or near the study area. The species currently found in the area will quickly become accustomed to the noise and will not be greatly affected.

Dust and other air pollution will be carefully controlled to meet air quality standards. This will result in little, if any, adverse effects on the biota beyond the edges of the immediate area. Some dust and vehicular or machinery emissions will be present in the area; however, these will be minor and should not adversely affect the biota currently present in the area.

As the mining front moves through an area, all vegetation will be cleared and all animals that do not move will be destroyed. Most animals will avoid the clearing machinery. Some rodents--mice, moles, gophers, etc.--will be

destroyed along with the aquatic animals in the streams and ponds unless the latter are previously removed. Those animals that avoid the devegetation will move into adjacent areas where they will cause overcrowding if the habitats are currently at or near carrying capacity. Some will eventually be lost in this case; however, after reclamation, if the habitats are replaced or allowed to replace themselves through natural succession, these animal species may re-populate to approximately their previous levels depending on the amount and quality of habitat available.

Assuming a time span of three to five years from initial clearing to some form of established ground cover at the beginning of reclamation and two or three more years for a restructuring of the vegetation, through natural invasion of nearby species, the grassland vegetation type will return to a more or less premining condition within five to eight years of its initial disturbance.

In all probability the Post Oak-Blackjack Oak upland forests will not be replaced or allowed to return. The inland fresh water marsh areas will probably be spared, as will the riparian areas since they are protected by various laws. All of the other vegetation associations will probably return if sufficient dispersal areas (unmined areas from which seeds can disperse into reclaimed land) are available. Given this situation, with the exception of Post Oak-Blackjack Oak forests which are removed for mining, the area would probably differ little from unmined areas within the surrounding lignite belt 25 to 50 years after mining.

3.3.1.6 Socioeconomics

Mining and gasifying Texas lignite in Central Texas would have a considerably larger impact on socioeconomic systems and land use in the region than the direct use scenario. The construction period would generate the most significant socioeconomic impacts. As shown in Table 3.3-3, the number of workers needed for construction could peak at around 3,000 for the plant and 250 for the 6.0 million ton per year mine. Total population increases (including families and secondary employment) resulting from employment directly associated with the plant will vary depending on specific local conditions, project construction schedule, and other factors. Ratios of total population increase to direct employment of 3:1 for the construction phase and 5:1 for the operation phase are possible. Using these numbers, total population increases of 9,750 and 5,000 for the construction and operation phases, respectively, are possible from the project.

Placed in the context of most Central Texas counties, such numbers represent significant impacts. When viewed cumulatively with other lignite development activities probable for this region, they become even greater in significance. Four major power plants and a comparable number of lignite mines are likely to be built in the Wilcox zone of Central Texas during the 1980's (see Figure 3.2-1). Even though the sites which are presently committed are dispersed over several counties in this region, the cumulative socioeconomic impacts of locating a gasification plant and mine among them could be extremely difficult to manage if construction of several of these projects was going on simultaneously. A brief analysis of issues and impacts likely to result from such a rapid growth situation is presented below.

TABLE 3.3-3. LABOR REQUIREMENTS FOR GASIFICATION PLANT¹

Facility	Construction Phase (Max.)	Construction Time	Operation Phase
6.0 mpty Mine Employ- ment	250	2-3 yrs.	400
150 billion Btu/day Gasi- fication Plant Employment	3000 ²	4 yrs.	600
Total Project Employment	3250		1000
Total Population Growth	9750 ³		5000 ⁴

¹ These estimates were averaged from several sources to provide indicators of impacts; they should not be used as definitive predictions.

² Includes a small crew for construction of a pipeline from the gasification plant to the Texas Gulf Coast.

³ Based on a population growth to direct employment ratio of 3:1.

⁴ Based on a population growth to direct employment ratio of 5:1.

Population Growth

While a portion of the construction force would come from the local population, many new jobs would be filled by in-migrants from outside the region or by long-distance commuters from the region's urban centers of Waco, Temple, and Bryan-College Station. Employment of persons living near the plant as a percentage of total employment would be small. This is especially true during the construction phase. Towns such as Hearne, Cameron, Rockdale, Mexia, and Marlin are likely to experience considerable growth. Many smaller communities

would also be affected, as would the rural countryside. Because of their larger size and greater existing infrastructural capacity, the region's urban centers are less likely to experience growth problems of a magnitude which would be difficult to manage.

Housing

Housing availability will be an important factor in the geographic distribution of population growth. Most areas in Central Texas have little unoccupied housing and the situation will probably grow worse as energy activity and related economic growth in the region increases. Financing for new housing could be an important constraint to increasing the housing supply. Unless well planned, injection of almost 10,000 new residents into the area for four years would probably be unmanageable for local governments and homebuilders. Use of mobile homes or "dormitory" housing would increase significantly. In the absence of county land use controls, problems resulting from uncontrolled housing growth are inevitable.

Public Services and Facilities

When a community is faced with rapid population growth, a number of public services and facilities must be examined with respect to their ability to serve the anticipated influx. Among these public services are schools, health care, police and fire protection, roads, water delivery, and municipal wastewater treatment. As with housing, most towns in Central Texas typically have little unused capacity with regard to these services. Financing of new public services and facilities may be difficult because the need for service

will appear before the tax base can be increased to pay for it. Moreover, a short-lived (construction) "boom" may not justify construction of new permanent facilities.

Public Safety

Rapid growth often causes stress on public safety systems. Many towns with rapid growth during construction periods experience increased crime rates and public disorders. Law enforcement systems are often unprepared for these additional problems and do not have the manpower, the experience, or funds to cope adequately with them.

The problem with fire protection can be just as serious if much of the population growth is scattered among numerous small towns and in unincorporated areas rather than clustered together. Volunteer fire departments are the only protection available in most communities in rural Texas. Serious damage from fires would almost certainly increase with rapid growth, particularly if growth is accommodated with sub-standard temporary housing.

Health Care

The level of health care in most small towns of Central Texas is limited more by the quantity and quality of health personnel (physicians, nurses and dentists) than by the physical facilities. Qualified personnel are difficult to attract and retain in rural areas. When the overall population of a region is low, it is difficult to support needed health care personnel. Hence, many residents of low density areas

must drive long distances to regional hospitals for care. Health care shortages will be further exacerbated by rapid population growth.

Education

As with other community services in a rapid growth situation, the school system typically becomes overcrowded. While school facilities in most Central Texas communities are adequate for current needs, energy development trends are likely to exceed this capacity in some locations. Given adequate funding, physical crowding can often be overcome in the short term by adding temporary buildings or classrooms. However, as with so many services, the school system must expand to meet the temporary construction phase demand which is greater than the long-term demand of the operation phase and must do so before the needed tax base is established. This situation often makes temporary buildings a preferred solution to building permanent structures.

Finding teachers to work in rural classrooms can be an equally serious problem. Rural areas have problems attracting and retaining qualified teachers. Compounding the situation is the fact that wages paid at new energy facilities are often much higher than the salaries of teachers, making teacher retention a serious problem.

Transportation

Lignite development in rural areas of Central Texas may present local transportation problems. State and federal highways are generally adequate for current uses, but county highway systems were designed to serve traditional farm and

ranch operations. Heavy trucks and substantially increased traffic loads can result in road deterioration and a greater number of accidents. Both these problems are more severe during construction phases than during plant operation.

Government and Fiscal Impacts

The gasification plant and mine would likely impact several communities in several counties. This situation raises the question of how to pay for new public services and facilities. This problem can be difficult to solve for several reasons.

First, there is the problem of adding new property to the tax base. The taxable property of the plant does not exist until after construction, but the need for public services can begin before construction even starts. As such, tax-base revenues are frequently too late to be of much help because of the long lagtime. Increasing the tax rate to overcome the delay in adding property to the tax base is likely to be met with resistance from long-time residents who are reluctant to add to their existing tax load in order to pay for new facilities to accommodate in-migrants.

Second, there is often the problem of governmental jurisdiction. If the demand for services is in one county or school district and the capital investment is in another, there is no change in the property base from which the first county or school district can finance the needed services. If population growth occurs outside city limits, the city can do little to control the growth, but may be called upon to provide water and sewerage services and other municipal services. The issue of governmental jurisdiction is further complicated if

the new facility is owned by a government entity and is thereby exempt from payment of taxes.

Finally, there is the problem of the construction boom being followed by a lower level of employment during the operation phase. In such instances it is possible to over-build during the boom period and have excess capacity after that without the necessary taxpayers to continue payment.

Solutions to many of these problems require action by government (primarily at the city and county levels) plus coordination with and cooperation from the private, project developer. These solutions entail both technical expertise and fiscal resources. Frequently, the people who manage small towns and county governments have not had any training or experience with rapid growth situations of the magnitude of a gasification plant and are ill-prepared to effectively manage and solve rapid growth problems. Some assistance is available from regional councils of governments (COG's) and state agencies, but small government managers do not always know how to obtain this help. As with teachers, the wages paid to public employees in rural areas are often not attractive when compared to those paid at a new facility and creates a problem with personnel turnover and expertise in public sector jobs. Assistance provided by the private sector developer of the project can play a major role in the timely solution of many of these problems.

Land Use

A problem common to nearly all energy-related developments is the lack of land use control mechanisms. Counties in Texas have very limited land-use control and planning authority.

Towns have zoning power, but this authority does not extend far enough into the surrounding countryside to be very effective. Even if counties and small towns had better land use controls, the element of uncertainty as to exact magnitude and timing of projects makes decisive, well-planned actions difficult to achieve.

The hypothetical gasification plant and mine are located in a rural portion of Central Texas where agriculture is the predominant land use. The active mine area covers as much as 1200 acres at any one time, and the gasification plant would require another 1,500 acres. Local reaction to cumulative impacts of removing multiple large tracts of agricultural land from production could be negative. Also, there may be land uses in the area which would conflict with a major industrial facility, depending on the specific site. Its proximity to parks and recreational facilities and other "sensitive" receptors is of concern.

Aesthetic Impacts

A large synfuels facility will be highly visible, depending primarily upon the topography. Visibility can be an important consideration in the actual site selection, but it is usually secondary to economic considerations such as water and lignite availability. Buffer zones are an effective way to reduce the visibility of the project to the public. Vegetation, topography, and coal piles may be effectively used to reduce visibility and noise.

Cultural Resources

Archaeological and historical resources may be threatened by construction and mining activities. Site surveys may need to be done to determine the presence of any cultural resources in the project area. The integrity of historic and archaeological sites in this region has been compromised by many years of agricultural activity, making it unlikely that any significant cultural resource will be found.

3.3.2 Transportation Corridor

Construction and operation of a pipeline for transportation of MBG from central Texas to Galveston Bay are not expected to have any significant impact on air, land, water, ecological, or human resources. Construction of the pipeline would occur in segments; impacts would be minimal and/or of short duration. No compression stations are expected to be required along the pipeline route. Except for special pipeline design requirements associated with shipment of CO and H₂ because of their small molecular size, compliance with procedures used in conjunction with natural gas pipelines are expected to be generally adequate for operation of the pipeline. Impacts from operation of the pipeline would be limited to potential leakage, rupture, and/or explosion. Because CO is a toxic gas, injection of an odorant (such as mercaptan used in natural gas) would improve detection of leaks and ruptures and reduce the likelihood of serious accidents.

3.3.3 Coastal Texas

3.3.3.1 Air Impacts

In the MBG scenario, MBG is substituted for natural gas in existing gas-fired boilers. While the level of emissions from combustion of these two fuels is expected to be comparable and that no significant increases in emissions will occur from fuel substitution, this is an area of uncertainty because of limited data from operating units firing MBG. In order to handle this uncertainty, the following discussion assumes that except for SO₂, there are no emissions from natural gas firing and that the MBG emission estimates presented in Table 2.2-17 reflect emission increases relative to natural gas as well as absolute emissions. Because of the recognized problem of potential consumption of the PSD increment for SO₂ in the Houston-Galveston area, SO₂ is treated explicitly.

As discussed in Section 3.2.2.1 and shown in Table 3.2-6, portions of the Houston-Galveston study area are classified as nonattainment areas for TSP. If MBG is burned in these areas offsets would have to be obtained. In obtaining offsets a greater than 1:1 reduction is required. In the rest of the study area, offsets would not be necessary, but the PSD increment for TSP would apply. An industry burning MBG would be required to demonstrate (by modeling) that the emission of 410 tons per year of particulate matter (from Table 2.2-17) would not consume the available PSD increment. The gaseous fossil fuels combustion NSPS of 0.1 lbs/10⁶ Btu must also be shown to be achieved.

Estimated SO₂ emissions are 41 tons per year. While SO₂ concentrations at CAMS No. 1 and No. 10 do not exceed the NAAQS, careful attention must be given to the impact of SO₂ emissions on the PSD increment. The sulfur content in the MBG of 0.2 grains of sulfur per 100 scf gives an emission factor of 0.0014 pounds SO₂ per MM Btu (gas quality of 418 Btu/scf). The EPA emission factor of 0.0006 lbs/MM Btu is based on 0.2 grains of sulfur per 100 scf of natural gas. Consequently, substitution of MBG with 0.2 grains sulfur per 100 scf for existing natural gas supplies would increase SO₂ emissions by 160 percent (41 tons per year for MBG versus 16 tons per year for natural gas.) Despite this increase, it is anticipated that SO₂ emissions from MBG will not seriously impact on the PSD increment. Modeling would be needed to estimate the amount of SO₂ increment consumed by this emission rate for a boiler located at a specific site. Should SO₂ emissions cause the PSD increment to be exceeded, additional sulfur removal equipment could be installed at the gasification plant in order to lower the SO₂ content of the cleaned gas.

Nitrogen oxides (NO_x) from the combustion of MBG are formed by thermal fixation of atmospheric nitrogen and by the oxidation of nitrogen compounds in the fuel. NO_x emissions (in the form of NO₂) are estimated at 13,686 tons per year. NO_x levels for the Houston-Galveston area are currently in attainment of NAAQS and are not expected to be significantly affected by the use of MBG. Modeling could be used to estimate changes in ambient concentrations.

Harris and Galveston counties are nonattainment areas for ozone. To locate an HC emitting source in Harris County offsets of HC emissions in a ratio greater than 1:1 would be

required. In Galveston County, because of its classification as a rural nonattainment area, no offsets would be required. As shown in Table 2.2-17, estimated HC emissions from MBG combustion are 82 tons per year.

3.3.3.2 Other Impact Areas

The firing of 150×10^9 Btu/day of MBG does not result in any additional water demand, wastewater discharge, or solid waste disposal as compared to the use of natural gas. No major construction would be entailed. Therefore, no impacts to soils, geology, topography, surface water, ground water, hydrology, or socioeconomics are expected from substitution of MBG for natural gas.

3.4 Major Direct Firing Impacts

3.4.1 Central Texas

3.4.1.1 Air Impacts

Lignite requirements under the direct firing (DF) scenario (4.2 million tons per year) are 70 percent of the lignite requirements of the gasification scenario due to the energy loss associated with lignite gasification. As a result, the mine would be 30 percent smaller (approximately 260 acres per year). The major air emission associated with a 4.2 mpty lignite surface mine is fugitive dust. Emissions from haul roads, overburden removal, and lignite storage are presented in Table 3.4-1.

TABLE 3.4-1. FUGITIVE EMISSIONS FROM A 4.2 MTPY SURFACE MINE*

Process	Uncontrolled Emissions (typ)	Control Efficiency (%)	Controlled Emissions (typ)
Haul Roads	1280-6330	85	192- 950
Overburden Removal	333-2080	-	333-2080
Stockpile Erosion	488	50	244

*The ranges reflect differences in mine depth, distances to storage facilities and other factors which will vary with time.

As discussed in Section 3.3.1, most fugitive dust will be deposited very close to the mining activities. Particulate levels within the mining area could be relatively high, but are expected to decrease significantly within two miles of the mine. The impact of these fugitive dust emissions outside the mine boundary would depend on location and alignment of the mine with regard to prevailing winds and would require site specific modeling.

Because the mine in the direct use scenario is not associated with a major fuel processing or conversion facility, the emissions from the mine are not subject to review under current PSD rules unless emissions from the load-out facility exceed 250 tons per year. In that the mine area is a rural area which is in attainment of NAAQS, TACB permitting is not required.

There will be lower emissions of NO_x and other pollutants from heavy equipment operating at the site. As with particulates, these emissions will have a low release height

and are expected to decline rapidly with distance from the site. These pollutants are therefore considered to have negligible impact on ambient air quality.

3.4.1.2 Geology, Topography, and Soils

The impacts described in Section 3.3.1.2 also apply to the direct use scenario. No new impacts are expected. Because of the smaller mine and proportionately smaller disturbed area, impacts which are related to the mine and disturbed area sizes (e.g., erosion impacts on stream sediment loads) will be proportionately smaller than in the MBG scenario. As in Section 3.3.1.2, no major impacts are expected.

3.4.1.3 Surface Water Hydrology

Impacts to surface water as a result of the operation of a 4.2 mtpy mine will be the same as or smaller than those discussed for the mine in Section 3.3.1.2 for the gasification scenario.

3.4.1.4 Ground Water Hydrology

The smaller mine size, smaller disturbed area, and lack of waste from a gasifier or other processing facility will reduce the water quality and quantity impacts described for the mine site in Section 3.3.1.4. The total ground-water requirement of 350 af/yr is only 5 percent of the MBG requirement. Since the Simsboro aquifer can adequately handle even the MBG water requirement, the only significant reduction of ground-water quantity impacts for the direct use scenario is for local water supplies very close to the potential mine/gasification plant well and pit locations. In the MBG scenario, ground-water quality impacts

from the high volume gasification plant waste disposal operations were avoided through a proper disposal system. However, the removal of this solid waste under the direct use scenario does reduce environmental risks related to ground-water quality impacts at the mine site.

3.4.1.5 Ecology

Impacts to the local ecology from the operation of a 4.2 mtpy mine will be comparable in nature to those discussed in Section 3.3.1.4. However, the magnitude of the impacts will be reduced below those in the gasification scenario, both due to the smaller mine size and the absence of the gasification plant and related secondary growth.

3.4.1.6 Socioeconomics

Socioeconomic impacts in the Brazos Valley would be limited to those of the mine construction and operation. Labor requirements associated with these activities are shown in Table 3.4-2. While the impacts of 350 mine workers (Table 3.2.5-1) would be far less than those of a large gasification plant, they could still be significant if the mine activities occur in combination with other energy developments anticipated for the area (see Section 3.3.1.6).

3.4.2 Transportation Corridor

A unit train will be used to deliver lignite to the coast. The major air impacts from unit trains are:

- Fugitive dust from loading, transit, and unloading operation

TABLE 3.4-2. LABOR REQUIREMENTS FOR THE DIRECT USE MINE¹

Facility	Construction Phase (Peak)	Construction Time	Operation Phase
4.2 mtpy Mine Employ- ment	250	2-3 yrs.	350
Total Population Growth	750 ²		1750 ³

¹See footnote 1 on Table 3.3-3.

²See footnote 3 on Table 3.3-3.

³See footnote 4 on Table 3.3-3.

- Carbon monoxide, hydrocarbon, nitrogen oxide and other emissions from locomotives

These emissions will be dispersed along the total 180-mile route. Particulate emissions will be greatest at the loading and unloading facilities and in the first 50 miles of movement. None of the counties along the train route are designated TSP nonattainment areas. Locomotive emissions are expected to have little impact on existing ambient concentrations of CO, HC, NO_x, and TSP. Impacts from all of these emissions will be highly localized near the train right-of-way.

The only other potentially significant impact associated with the rail movement of lignite is the socioeconomic impact along the transportation route. These socioeconomic impacts include disruption to communities through which unit trains will travel, accidents at railroad/highway grade crossings, and increased noise levels experienced by residents located near

the track. The transportation of western coal and lignite by unit trains is expected to increase steadily in the future and will have disruptive effects on Texas communities. In 1980 an estimated nine western coal unit trains either entered or left the state every day. The additional traffic from the transportation of lignite will further restrict highway movement and affect life in some communities. The design lignite movement would increase the movements over a single rail line by four trains per day. Assuming an average speed of 20 miles an hour and a 3400 foot long train, each grade crossing along the line would be blocked for an additional eight minutes per day. Depending upon existing highway and rail traffic characteristics (such as grade crossings important to hospital or fire department access), this additional delay may or may not represent a significant impact. In situations where this additional delay is a problem, grade separations (overpasses or underpasses) or rail rerouting to bypass the affected area may be desirable.

Prediction of the number of accidents and fatalities at railroad/highway grade crossings due to the design movement of lignite is dependent upon route specific characteristics such as the number and location of crossings, train and vehicle density, and the type of crossing protection. Because of the route specific requirements of such analysis, no estimates have been made for this study. It should be noted, however, that existing data indicate that accident rates and train traffic density are related nonlinearly with accidents increasing at a slower rate than train traffic. This result may be explained by greater train awareness and grade crossing caution by vehicle drivers as a result of increases in train traffic.

The main sources of noise from unit train operations are locomotive motors, hopper car vibrations, and the interaction between wheels and track. The standard by which noise is measured is the day-night average sound level (L_{dn}) which weights nighttime noise more heavily than daytime noise. As with grade crossing accidents, assessment of noise impacts is highly route specific, depending on existing rail traffic levels, other background noise, and population densities near the track. Further, the acceptability of noise varies significantly from individual to individual. Noise in urban areas may be reduced somewhat by the construction of sound barriers, but may require rerouting of track away from urban centers if severe.

Land will be required at the points of origin and termination of shipment and at various points along the route where additional sidings may be required to accommodate increased rail traffic. It is assumed that no new mainline track (as opposed to sidings) will be required by the design lignite movement. Another land use impact from the transportation of lignite by rail is the potential increase in wildfires. While the problem has been identified in several western states,¹¹ the potential extent of such fires in the Texas coastal plain has not been estimated.

3.4.3 Coastal Texas

3.4.3.1 Air Impacts

The major pollutants of concern when firing lignite are particulates, sulfur oxides, and nitrogen oxides. Hydrocarbon and carbon monoxide emissions are usually low under normal operating conditions. Table 2.3-5 presents EPA emission

factors, NSPS for coal fired electric utilities, and the total estimated emissions based on each. The impacts of each on the Houston-Galveston area are considered below.

Particulate emissions, 821 tons per year, at design conditions, are small relative to sulfur and nitrogen oxide emissions. If these emissions were to take place in a TSP nonattainment area near the Houston Ship Channel, offsets would be necessary. The Texas City area is an attainment area for TSP and no offsets would be required under NAAQS. However, dispersion modeling should be conducted to indicate the increase in ground level concentrations and the impact on the PSD increment.

Controlled emissions of SO₂ are estimated at 10,129 tons per year. Although both Harris and Galveston Counties are classified as SO₂ attainment areas, there is concern over the impact of PSD rules on the construction of new sources emitting SO₂ (see Section 3.2.2.1). Given current PSD rules, it is likely that several SO₂ sources could be sited in the Galveston Bay area. The extent to which these initial sources will consume the increment available for subsequent growth is uncertain without detailed knowledge of source locations and modeling.

The estimated NO₂ emissions of direct firing are 16,425 tons per year. There are no PSD increments for NO₂. Both Harris and Galveston Counties are NO₂ attainment areas. Ground level NO₂ concentrations are not expected to exceed the NAAQS.

Harris and Galveston Counties are nonattainment for ozone (O₃). Hydrocarbon emissions from direct firing are estimated at less than 2,108 tons per year. To locate in Harris-

County, HC emissions offsets would have to be obtained in a ratio greater than 1:1. Galveston County is a rural non-attainment area and will not require offsets.

Carbon monoxide (CO) emissions are estimated to be 2,108 tons per year. This amount of CO should have little effect on ambient CO concentrations. The NAAQS for CO is not expected to be exceeded. There is no PSD increment for CO.

3.4.3.2 Geology, Topography and Soils

No adverse impacts on geology, topography, and soils are expected from activities associated with the direct firing scenario, provided that land requirements (especially for solid waste disposal) do not require the use of land with significant soil resources. It is very likely that suitable land would be present in Galveston County. In the Houston Ship Channel area, available land may be a significant constraint.

3.4.3.3 Surface Water Hydrology

The only discharge associated with the direct firing of lignite as opposed to MBG is the ash pond overflow of 78 million gallons/year. This discharge represents less than 0.2 percent of the 1964 permitted discharges in the Texas City area. No significant adverse impacts from such a discharge are expected to occur.

3.4.3.4 Ground Water Hydrology

For the DF scenario, the following differences (from MBG) are significant to ground-water impacts:

- A large water requirement exists at the utilization site, and
- A large solid waste disposal volume (about one-half the volume of the MBG mine site) at the utilization site.

An additional 500 gpm is required for the direct-use boiler beyond requirements for a conventional natural gas-fired boiler, primarily for scrubber operation and ash sluicing. As described in Section 3.2.2.4, ground-water resources in this area are sufficient to accommodate this demand. A single production well would probably provide this water supply. However, problems associated with land subsidence, surface fault activations and saltwater encroachment may occur unless proper precautions are taken.

The disposal of 1,000,000 tons/year of bottom ash, fly ash, and SO₂ scrubber sludge (equaling roughly 13,000 acre-feet over a 30 year period) poses a significant potential ground-water quality impact. Although these materials are relatively low risk, their large volume results in the potential for relatively high pollutant loading to the local ground-water system at the disposal site. Unlike the mine site, the Houston-Galveston area ground-water resource is highly developed and many water supply wells exist. Especially in the Houston area, many high-volume public supply wells exist which would probably constrain solid waste siting. Also, in some areas, hurricane flood potential, subsidence, and faulting may threaten solid waste disposal sites. However, proper disposal system design, site selection, and ground-water monitoring can allow disposal of this waste without adverse impacts. In general, even though the waste volume is lower, the Houston-Galveston area solid waste disposal poses

higher costs and environmental risk relative to ground-water quality impacts than mine-area disposal of MBG solid waste. Transportation of the solid wastes back to the mine or to an alternate location out of the coastal area may be required.

3.4.3.5 Ecology

The major ecological impact of the direct use of lignite in the coastal zone is the required use of additional land that is already extremely limited. In Galveston Bay, an estimated 25,000 acres, or 25 percent of the bay's valuable marsh area, has been lost to industrialization and urbanization.

The direct firing scenario estimates that 23.5 acres will be required for reserve lignite storage and an additional 14.7 acres per year of landfill for the solid effluents. The landfill requirement will be 441 acres for the 30 year life of the plant. This acreage is a significant amount in an area of ecologically sensitive wetlands. Permitting requirements may dictate that the landfill site(s) be located in areas of low fauna and flora diversity, avoiding areas of valuable or unique plant communities or animal populations. This may necessitate the use of landfill sites far removed from the plant site.

3.4.3.6 Socioeconomics

Construction of the hypothetical lignite boiler near the Gulf Coast would take four years. The largest increment of construction employment is estimated at 1000 workers. The labor would be required in the Houston-Galveston area and could be easily accommodated without noticeable adverse impact on public sector services.

3.5 Comparison of Impacts from MBG and DF Scenarios

Section 3.5 compares the environmental and socioeconomic impacts associated with the MBG and DF scenarios developed in Chapter 2. A simplified presentation of this comparison is presented in Table 3.5-1; the numbers assigned as impacts are qualitative in nature and reflect the professional judgement of the Radian research team. The two major areas of potential impact are those associated with air quality for the DF scenario and with socioeconomic considerations in the MBG scenario.

3.5.1 Air Quality

The most significant air quality impact is in the coastal region when lignite is directly fired. The severity of this impact results from the existing and projected level of air quality in the region relative to NAAQS for ozone and PSD requirements for SO₂. The problem of nonattainment of NAAQS for ozone in the Houston-Galveston area and other industrial areas along the coast could be exacerbated by higher levels of NO_x and HC estimated in the DF scenario. The constraints posed by PSD requirements along industrialized areas of the coast is also of significant concern to the potential for lignite use in the region. Although August, 1980 changes in EPA's method for computing PSD increment consumption have made it possible to locate additional industrial sources in the region,¹² it is anticipated that SO₂ emissions resulting from conversion from natural gas to either fuel oil or coal will locally consume a significant portion of the available increment. The direct use of lignite in the region will depend on both the specific location and timing of the project; detailed atmospheric modeling is needed to estimate the magnitude of increment

TABLE 3.5-1. COMPARISON OF IMPACTS FROM MBG AND DF SCENARIOS*

	Mining	Gasifi- cation	Transpor- tation	Utili- zation	Overall
<u>Air Quality</u>					
MBG Scenario	2	2	0	2	2
DF Scenario	1	0	1	3	3
<u>Water Quality</u>					
MBG Scenario	1	2	0	0	2
DF Scenario	1	0	0	1	1
<u>Water Use</u>					
MBG Scenario	2	2	0	0	2
DF Scenario	2	0	0	2	2
<u>Solid Waste</u>					
MBG Scenario	1	2	0	0	2
DF Scenario	1	0	0	2	2
<u>Land Use</u>					
MBG Scenario	2	2	1	0	2
DF Scenario	2	0	0	2	2
<u>Ecology</u>					
MBG Scenario	2	1	1	0	2
DF Scenario	2	0	1	1	2
<u>Socioeconomic</u>					
MBG Scenario	2	3	0	0	3
DF Scenario	2	0	1	1	2

* 0-negligible or no impacts

1-minor impacts

2-moderate impacts

3-major impacts

consumption and potential constraints posed by existing PSD regulations at a specific site. While of less significance, the status of air quality in the coastal region may also impose moderate constraints on the MBG scenario.

Based on projected development of lignite-fired power plants throughout the lignite belt, PSD requirements (especially as relate to SO_2) may pose a moderate constraint to the siting of a gasification plant. As in the coastal area, the timing and specific location of the plant will play a significant role in determining the magnitude of this constraint. The ability to site the gasification plant at alternate locations provides significant flexibility and should reduce the severity of potential air quality siting constraints. The impacts from the mine are of greater importance under the MBG scenario due to the inclusion of the mine in PSD calculations as a secondary source to the gasification plant.

All other impacts are rated as being of minor or negligible importance because of relatively small magnitude, localized nature, and/or good dispersion characteristics.

3.5.2 Water Quality

All water quality impacts are estimated to be of minor or negligible importance with the exception of potential impact from the gasification plant wastewater which is rated as moderate. Treatment technology to remove pollutants from the wastewater stream is expected to be extensive and will remove pollutants to low concentrations. Although similar treatment technology is presently employed in the steel industry, the effluent from the gas clean-up system is somewhat harsher and may be harder to treat. The assignment of a

moderate impact rating is based on both the potentially toxic organic and trace element content of the treated effluent and the uncertainty about system operation because of limited experience. In addition to expected low pollutant concentrations in the final effluent, significant dilution by existing surface water flows is expected to occur.

3.5.3 Water Use

All water use impacts are estimated to be of minor-to-moderate importance. Due to insufficient long-term supplies of uncommitted surface water, ground water will be used for process, cooling, and pollution control equipment needs of the gasifier. The surface mines associated with both scenarios will have moderate impacts on surface and ground water supplies because of dewatering activities, construction of on-channel sedimentation ponds, and rechannelization of streams. Total water requirements for the gasification plant and associated mine are 6,600 and 590 acre-feet per year, respectively. Individual wells in the Simsboro Sand are capable of pumping 4,000 acre-feet per year. It is therefore not anticipated that the plant will have a major impact on ground water supplies, although lowering of the water table within up to a mile of the well field may occur and require the deepening of some existing wells. Total ground-water requirements in the DF scenario for Central Texas are 350 acre-feet per year, but the lignite-fired boiler will have a substantial water requirements which will have to be met with either surface or ground water on the Gulf Coast. Because of subsidence, surface fault activations, and hurricane flooding potential, moderate problems are posed for obtaining ground water supplies even though the water is physically available.

3.5.4 Solid Waste

The disposal of solid waste from the gasification plant and from the direct-fired lignite boiler on the coast are judged to have moderate impacts. The solid waste from the gasification plant is larger in volume than at the lignite boiler along the coast. It is also likely that the solid waste sludge from the biological treatment system at the gasification plant will be classified as a hazardous waste under RCRA. The disposal of the gasification plant wastes will be less constrained by location, however, due to greater availability of land within the plant boundary. In addition to limited on site storage space, the coastal location is subject to periodic flooding which will mean greater potential for environmental impact if solid waste is disposed of on-site.

3.5.5 Land Use

The most significant land use impacts are those associated with the gasification plant and direct-fired lignite boiler. In addition to space used for the plants themselves, significant land use will result from the disposal of the solid wastes. Mining impacts, while affecting a large area, are rated as moderate due to the historical use of the mining area as pasture and range land and the general absense of prime farmland in the region.

3.5.6 Ecology

The major ecological impacts are those associated with wildlife habitat destruction from mining. Current reclamation practices are not adequate to restore these habitats to

pre-mining quality. From a regional perspective, these impacts are initially of moderate importance, but are expected to decrease with time. Other impacts are of minor or negligible importance.

3.5.7 Socioeconomics

A mine and gasification plant will have a total construction work force in excess of 3,000 persons and an operating force of 1,000 persons. When combined with the labor required for lignite-fired power plants and other economic development ongoing in the region and from secondary population and employment growth, the pressures on housing, public utilities, education, health care, and transportation could be of major significance. The public sector fiscal impact from providing increased services prior to deriving tax revenues from the project as well as the provision of services to immigrants who live outside the tax jurisdiction of the project are significant aspects of this problem. Secondary impacts from this growth on water quality and land use may also be important. Impacts from the mine in the DF scenario will be of moderate importance. Other impacts are of minor or negligible importance.

Footnotes - Chapter 3

- ¹ Kaiser, 1980, p. 24.
- ² Gale Research Company, 1978, p. 960.
- ³ Texas Water Quality Board, 1975, p. 18.
- ⁴ Lacy, 1979, pp. 148-174.
- ⁵ Brazos Valley Development Council, 1979, pp. 49-51.
- ⁶ Gale Research Company, 1978, p. 968.
- ⁷ Sheffield, 1979, pp. 14-17.
- ⁸ Espey, 1971, p. 5-46.
- ⁹ Lacy, 1979, pp. 179-206.
- ¹⁰ Kennedy, 1980, pp. 17.6-17.8.
- ¹¹ Rogozen, 1977, pp. 72-76
- ¹² 45 Fed. Reg. 52676

4.0 REGULATORY IDENTIFICATION

4.1 Overview

The objectives of Chapter 4 are as follows:

- To catalog state and federal regulatory requirements which may impact the MBG and DF scenarios; and
- To define the nature and extent of the regulatory impacts associated with each scenario.

The above stated objectives are achieved by analysis of the relevant statutes as well as the substantive rules of the federal and state agencies charged with administering environmental regulatory programs. Secondary sources were reviewed as necessary for interpretation of statutes and rules. In addition, information on agency interpretation and program status was obtained through discussions with appropriate agency personnel.

Chapter 4 is organized to correspond to areas of environmental concern. Section 4.2 describes the informational and procedural requirements of the National Environmental Policy Act of 1969 (NEPA) which overlie many federal environmental actions such as permit approvals. Section 4.3 describes various federal, state, and local land use controls, including surface mining and reclamation. Section 4.4 catalogs federal and state water quality controls. Section 4.5 identifies federal and state water use controls which include authorizations necessary for dam and levee construction, dredging and filling operations, and beneficial use of water for mining and

industrial purposes. Section 4.6 describes federal and state air quality controls, emphasizing recent developments concerning EPA's Prevention of Significant Deterioration (PSD) and emission offset programs. Section 4.7 identifies the requirements of federal and state solid waste disposal programs. Section 4.8 describes the premanufacture notification procedures required by the Toxic Substances Control Act for any new chemical substance produced by a proposed facility. Section 4.9 identifies the regulatory requirements associated with protection of wildlife and endangered species, and describes the requirements associated with protection of cultural and historical resources. Section 4.10 summarizes the permits and approvals required for each component of the MBG and DF scenarios.

Each section of the report generally includes a description of the following regulatory elements:

- Statutory authority;
- Program implementation, including relationship between state and federal programs and to other state and federal environmental regulatory programs;
- Performance standards and requirements;
- Procedural requirements; and
- Applicability of the program standards and requirements to the MBG and DF scenarios.

4.2 National Environmental Policy Act of 1969

4.2.1 Introduction

The National Environmental Policy Act of 1969 (NEPA), effective January 1, 1970, requires all federal agencies, with respect to major federal actions affecting the quality of the human environment, to submit to the President's Council on Environmental Quality (CEQ) a detailed Environmental Impact Statement (EIS) on the following:

- The environmental impact of the proposed federal action;
- Any adverse environmental effects which cannot be avoided should the proposal be implemented;
- Alternatives to the proposed action;
- The relationship between local short-term uses of the environment and the maintenance and enhancement of long-term productivity; and
- Any irreversible and irretrievable commitments of resources which would be involved if the proposed action should be implemented.¹

The purposes of these provisions are (1) to include in the agency decision-making process careful consideration of all

environmental effects of proposed actions and (2) to explain the potential environmental effects of those actions and their alternatives to the public.

The CEQ's general regulations implementing NEPA provide for the following:

- Preparation of an Environmental Assessment (EA) to determine whether an EIS is necessary for the action, unless the action is one which normally requires an EIS;
- Preparation of a formal "finding of no significant environmental impact" document if the agency determines on the basis of the EA not to prepare an EIS;
- Preparation of an EIS, if necessary, which shall be widely disseminated for comment by various federal and state agencies and by the general public and which may be the subject of a public hearing.²

Many federal agencies--DOE, EPA, FERC--have proposed rules and regulations for integrating these requirements into their decision processes, but only a few agencies have adopted final regulations (Fish and Wildlife Service, Department of the Interior).

4.2.2 Criteria/Elements

Major Federal Actions which normally will require an EIS are defined under the CEQ regulations as any actions "with

effects that may be major and which are potentially subject to Federal control and responsibility." They may include new or continued activities, physical projects, and policies or plans which significantly alter an agency's programs. Major actions may take the form of funding assistance, permit approval, or direct implementation.

Although NEPA is generally applicable to all federal actions significantly affecting the quality of the environment, Congress has expressly exempted a number of federal environmental permit programs from NEPA requirements. The following is a summary of the applicability of NEPA requirements to the principal federal environmental statutes which regulate lignite mining, lignite gasification, or direct firing of lignite in an industrial boiler:

- Federal Surface Mining Control and Reclamation Act of 1977--approvals of state programs, promulgation of federal programs, and implementation of federal lands programs are exempt from NEPA. Adoption of permanent program regulations is, and granting of permits by OSM may be, subject to NEPA. Granting of permits by states under OSM-approved programs is exempt from NEPA;
- Clean Water Act--National Pollutant Discharge Elimination System (NPDES) permits are subject to NEPA if granted by the Environmental Protection Agency (EPA) to "new sources"; state-issued permits under federal delegation of NPDES authority are not subject to NEPA;

- Dredge and Fill Permits--Corps of Engineers permits granted under Section 404 of the Clean Water Act and Sections 9 and 10 of the Rivers and Harbors Act are subject to NEPA;
- Clean Air Act--all EPA and state approvals are exempt from NEPA; and
- Resource Conservation and Recovery Act--permits issued by EPA for hazardous waste management facilities are subject to NEPA; state-issued permits are exempt.

Where dual state/federal permit programs exist, NEPA will apply only to federal program decisions. Where a state agency has received a delegation of authority to administer a federal program, NEPA will not apply to the state agency's decisions. Texas has received a delegation of federal authority to administer the federal surface mining and reclamation program and has recently received interim authority to administer the RCRA hazardous waste permit program. The Corps of Engineers Section 404 permit program and the EPA NPDES program are federally administered, and NEPA does apply to these agencies' decisions.

The following are key elements of a NEPA EIS under CEQ's general regulations:

- A summary stressing major conclusions, areas of controversy, and issues to be resolved;
- Statement of "purpose and need" for the proposed action;

- Description of the proposed action/alternatives (the "no action alternative" and other reasonable alternatives);
- Description of the affected environment including those resources or components in the affected environment determined to be significantly impacted;
- Discussion emphasizing significant environmental consequences of the proposed action and alternatives, including direct and indirect, short- and long-term, beneficial and adverse impacts; must consist of multidisciplinary analysis, including analysis of possible connected actions and cumulative impacts; worst-case analysis is required where impacts are determined to be potentially significant but are uncertain;
- Analysis of net energy requirements and conservation potential of the proposed action/alternatives and mitigation measures;
- Mitigation measures necessary to eliminate or reduce to an acceptable level the adverse impacts identified in the EIS;
- Possible conflicts of the proposed action or alternatives with related programs or objectives of other federal, regional, state, and local plans and policies;

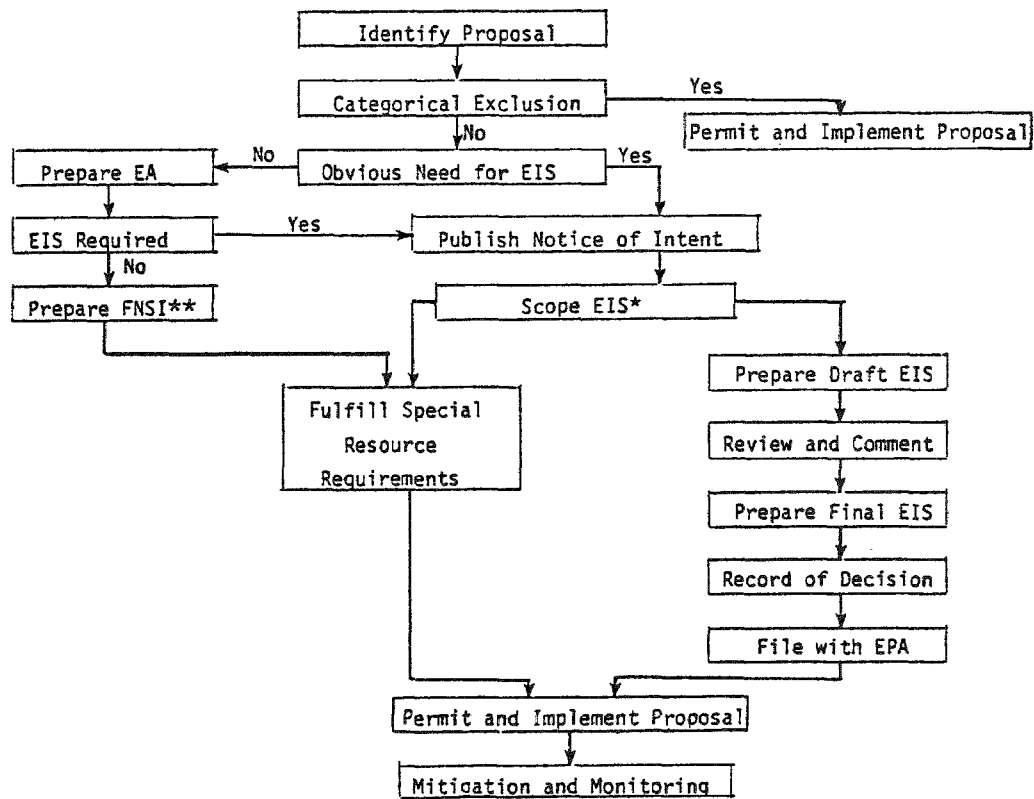
- List of preparers to demonstrate professional competence of the EIS team.

4.2.3 Permit Process

When a proposed action has been determined to require an EIS, the "scoping" process is begun. The responsible federal agency must prepare and publish a Notice of Intent in the Federal Register. It must briefly describe the proposed action/alternatives, the scoping process, and state the name and address of the lead agency representative to answer questions about the proposal and EIS.

The "lead agency" is the one with primary responsibility for either preparing or overseeing preparation of the EIS, and for approval or denial of the proposed action which is the subject of the EIS. The lead agency is also responsible for announcing and conducting scoping meetings, "kickoff" meetings, and public hearings on the proposed action and EIS. It must solicit and incorporate input from "cooperating agencies;" those federal agencies which have some interest in the proposed action or a role in its permitting or operation. The lead agency is responsible for requiring mitigation measures to reduce or avoid negative impacts identified in the EIS. Finally, it must monitor the implementor of the proposed action to assure compliance with the mitigation measures. Such measures should be set out in the EIS and the project approval mechanism (for example a permit, grant or lease allowing implementation of the proposed action).

Figure 4.2-1 illustrates the sequence of events in the NEPA EIS process.



Adapted from Kitto, 1980

* It is at this stage that institutional analysis and multi-jurisdictional coordination are paramount in order to avoid substantial and costly project delays.

** Finding of No Significant Impact

Figure 4.2-1. Sequence of Events: NEPA EIS Process

4.2.4 Applicability

NEPA requirements are significant to federal permitting processes for several reasons. First, most agencies place much of the working burden on the applicant to submit factual information required for preparation of the agency's EA and/or EIS through submission of Environmental Information Documents (EID). Preparation time by the agency can, therefore, be shortened somewhat if the applicant anticipates an EIS requirement and begins to gather data early in the permitting process. Second, the environmental review required for an EIS must include comments and participation from other governmental agencies and from the public. The NEPA environmental review process provides a mechanism for interagency and intergovernmental coordination. The breadth of the process, however, may inject unforeseeable regulatory problems into the permitting process, thereby extending the project lead time.

Several of the federal permitting processes--NPDES, 404--applicable to construction of a lignite-fired gasification or industrial facility and to mining of lignite will invoke NEPA requirements. It is likely that a major gasification or lignite-fired industrial boiler facility will require an EIS.

Footnotes - Section 4.2

¹ 42 U.S.C. §4341, et seq.

² 43 Fed. Reg. 55992 (1978).

4.3 Land Use Controls

4.3.1 Introduction

Three distinct sets of land use controls must be considered in connection with the two scenarios:

- Surface mining and reclamation controls which are identical for both scenarios;
- Controls associated with transportation of gas via pipelines (MBG scenario) and lignite via rail (DF scenario); and
- Controls associated with locating a new gasification plant under the MBG scenario or a new industrial boiler facility under the DF scenario.

Specific programs under each generic control and the applicability of these programs to the two scenarios are summarized in Table 4.3-1.

Various entities assume administrative responsibility for the programs listed in Table 4.3-1. Regulation of surface mining and transportation is under authority of the Texas Railroad Commission (TRC). Site-related controls associated with new industrial facility development are usually administered at the local level. The National Flood Insurance Program is, for example, administered by county and municipal entities. The Texas Coastal Program, a regional program administered by the Texas Energy and Natural Resources Advisory Council, also affects industrial siting decisions.

TABLE 4.3-1. LAND USE CONTROLS

Generic Controls	Specific Programs	Applicability
Surface Mining	Surface Mining Control and Reclamation Act (SMCRA), 30 USC 1201, as amended	Superseded by Texas program under both scenarios
	Texas Surface Coal Mining and Reclamation Act, Vernon's Ann. Civ. St. Natural Resources Code §131.001, <u>et seq.</u>	Applies to the surface mine with equal force for both scenarios
Transportation	Texas Railroad Commission (TRC) plenary authority over railroad construction within the state, including power of eminent domain	Affects construction of railroad spurs necessary under the DF scenario
	Texas Railroad Commission plenary authority over pipelines (operating permit program)	Applies to MBG scenario if common carrier or gas utility
	Federal, state, local, and private land use controls associated with pipeline construction (see Table 4.3-4)	Applies to MBG scenario if pipeline is not a common carrier and not a gas utility
New Industrial Facilities	National Flood Insurance Program	Affects siting decisions for both the gasification facility (probably under the riverine flood control program) and the new industrial boiler under the DF scenario (coastal flood or riverine flood programs)

(Continued)

TABLE 4.3-1. LAND USE CONTROLS (Continued)

Generic Controls	Specific Programs	Applicability
	Coastal Zone Management Program (Texas Coastal Program)	Affects siting decisions in the coastal zone (first tier of Gulf Coastal counties) and will apply to any new industrial facilities located in the coastal zone

Because of the relatively greater importance of land use controls at the surface mining phase of the two scenarios, those controls are analyzed in more detail below. Pipeline construction under the MBG scenario is also likely to raise important questions. Railroad transportation, however, is unlikely to raise significant issues. Accordingly, there is some discussion of land use controls associated with pipelines, but railroads are treated cursorily.

Local controls are largely beyond the scope of the present task. These will, however, be considered peripherally insofar as they relate to federal or state land use/environmental protection programs.

4.3.2 Surface Mining and Reclamation

4.3.2.1 Background

In order to mitigate impacts from increased surface mining of lignite, the State enacted the Texas Surface Mining and Reclamation Act in January 1976. The Texas law established a permit system, reclamation standards, public hearing requirements, enforcement provisions, and procedures for designating land unsuitable for mining. Administration of this law became the responsibility of the Texas Railroad Commission (TRC).

The Texas law was amended to reflect requirements established by federal legislation, the Surface Mining Control and Reclamation Act of 1977 (SMCRA).¹ The revised Texas law, the Texas Surface Coal Mining and Reclamation Act, was passed by the Legislature in December 1979. The Texas law and surface mining regulations promulgated by the TRC were approved in February 1980, by the U.S. Office of Surface Mining (OSM), Department of Interior. Texas thus assumed exclusive jurisdiction over the regulation of surface coal mining and reclamation operations within its borders.

With regard to minimum permit application requirements, performance standards, procedures, approval or denial criteria and designation of areas unsuitable for mining, the TSCMRA and Texas Railroad Commission regulations follow the intent and language of SMCRA and the OSM regulations with only two significant deviations. The Texas statutory and regulatory provisions which correspond to the federal statutory and regulatory provisions are shown in Table 4.3-2.

TABLE 4.3-2. SURFACE MINING CONTROLS: CORRESPONDING FEDERAL AND STATE OF TEXAS
STATUTES AND REGULATIONS

	SMCRA	OSM Regulations	TSCMRA	Texas Regulations
Minimum Permit Application Requirements	Sections 506- 509, 512	Parts 760-761, 771, 776, 778, 779, 780 and 785	Sections 11- 12, 14-18, 24-25	Parts 770, 771, 776, 778, 779, 780, 785
Performance Standards	Section 515	Parts 800, 805, 806, 810, 815, 816, 822, 823, 826, 827 and 828	Section 23	Parts 800, 805, 806, 816, 819, 822, 823, 828
Procedural Guide	Sections 513- 514	Part 786	Section 20	Part 786
Permit Approval or Denial Criteria	Section 510	Part 786	Section 21	Part 786
Designation of Areas Unsuitable for Mining	Section 522	Parts 760, 762, 764, 765 and 769	Section 33	Parts 762, 764

The TSCMRA does not replace or override other state and federal programs designed to protect the environment from the various impacts a surface mine will cause. The Act does, however, provide for coordination of review and issuance of permits for surface mining operations with the following:

- Any other applicable federal or state permit process, including permits required by the
 - Clean Water Act, as amended²,
 - Clean Air Act, as amended³,
 - Resource Conservation and Recovery Act⁴;
- Requirements of EPA-approved water quality management plans under §§ 208 and 303(c),(e) of the Clean Water Act⁵;
- Applicable requirements of
 - The Endangered Species Act of 1973, as amended⁶,
 - The Fish and Wildlife Coordination Act, as amended⁷,
 - The National Historic Preservation Act of 1966, as amended⁸, and
 - Executive Order 11593 which concerns identification and preservation of cultural resources of historic significance.

As emphasized in the introductory comments, surface mining and reclamation controls apply with equal force to both scenarios. The performance standards and procedural requirements discussed in Subsections 4.3.2.3 and 4.3.2.4 will apply to any lignite mine with output greater than 250 tons per year.

4.3.2.2 TSCMRA Performance Standards Criteria

TRC surface mining regulations establish permanent program performance standards for coal exploration⁹ and for surface mining activities.¹⁰ In this subsection, both operating and reclamation standards are described.

Exploration

During exploration, operations must be conducted so as to protect "habitats of unique value" and to "minimize environmental damage."¹¹ Habitats of unique value include at least those described in Section .144 of the TRC regulations:

- Threatened or endangered species of plants or animals listed by the Secretary under the Endangered Species Act of 1973, as amended,¹² and their critical habitats;
- Species such as eagles, migratory birds or other animals protected by state or federal law, and their habitats; or other species identified through the consultation process pursuant to §.133; or
- Habitats of unusually high value for fish and wildlife, such as wetlands, riparian areas, cliffs supporting raptors, areas offering special shelter or protection, reproduction and nursery areas, and wintering areas.

Exploration Performance Standards

Nearly one-third of the exploration performance standards relate to roads and road use. Minimal disruption of existing conditions is the main thrust of these regulations. If roads must be damaged or rerouted, these regulations require that they be restored following exploration.

Remaining regulations establish general standards for reclamation. These regulations include provisions for the following:

- Reestablishment of the approximate original contour;
- Topsoil removal, storage, and redistribution as necessary to assure successful revegetation;
- Revegetation;
- Preservation of all existing ephemeral, intermittent, and perennial streams and stream-beds (small and temporary diversions are allowed);
- Control of surface water runoff to prevent erosion and to minimize stream sedimentation by using "the best technology currently available;"
- Casing and sealing of drilled holes;
- Removal of facilities and equipment;

- Minimal disturbance of the prevailing hydrologic balance including sediment control measures; and
- Safe handling and disposal of toxic or acid-forming materials.

4.3.2.3 Surface Mining Performance Standards

Performance standards for surface mining activities are considerably more detailed than those for exploration. These standards are summarized in Appendix A in conjunction with related permit requirements discussed in Subsection 4.3.2.4.

Generally, mining performance standards are designed to protect existing environmental values (air, water, hydrologic balance) during mining operations and to ensure restoration of the site to a condition environmentally similar to pre-mine conditions. Particular emphasis is given to the following areas:

- Topsoil removal, storage and redistribution¹³;
- Hydrologic balance, including both surface water and groundwater protection¹⁴ ;
- Use of explosives¹⁵;
- Disposal of excess spoil¹⁶;
- Management of coal processing waste banks¹⁷;
- Protection of air quality¹⁸ ;

- Protection of fish, wildlife and related environmental values¹⁹;
- Backfilling and grading requirements²⁰; and
- Revegetation²¹.

As in the case of coal exploration, mining operation regulations contain detailed requirements for construction, reconstruction, maintenance, and use of roads and highways. Other standards address such problems as protection of existing pipelines, slide prevention or protection from other damaging events, protection of nearby underground mining operations, and the casing and sealing of drilled holes. Additional standards were developed for special categories of mining such as operations in prime farmland areas or on alluvial valley floors.

4.3.2.4 Procedural Requirements Under TSCMRA

All phases of lignite surface mining operations in Texas--exploration, mining and reclamation--are subject to TRC approval. TRC regulations promulgated under the TSCMRA provide that after September, 1980, "no person shall conduct surface coal mining and reclamation operations in the state without first having obtained a permit from the Commission." [TR .009 (a)(1)]. Subsection (d)(1) of the same section requires permits for exploration operations.

Subchapter G of the TRC Coal Mining Regulations is the heart of the permit application process. Permit application requirements and review procedures are set forth in nine separate parts of subchapter G as follows:

- Part 770 - General requirements for surface mining and reclamation permits. General requirements for obtaining approval of proposed exploration.
- Part 771 - Filing deadlines, format and contents general requirements, and permit fees.
- Part 776 - Minimum requirements for approval of proposed coal exploration procedures.
- Part 778 - Surface mining permit applications: minimum requirements for legal, financial, compliance, and related information.
- Part 779 - Surface mining permit applications: minimum requirements for information on environmental resources.
- Part 780 - Surface mining permit applications: minimum requirements for reclamation and operation plan.
- Part 785 - Requirements for permits for special categories of mining.
- Part 786 - Review, public participation, and approval of permit applications and permit terms and conditions.
- Part 787 - Administrative and judicial review of TRC decisions on permit applications.

Procedural and substantive requirements are summarized in Appendix B.

4.3.3 Transportation-Related Controls

4.3.3.1 Background

Under the DF scenario, Radian assumed that transportation will be by unit train from the mine site to the end user. Existing rights-of-way and track could be used, with the exception that short feeder lines (spurs) from the mine site to the main line and from the main line to the end use facility will be necessary. Discussion of land use controls associated with construction of new railways is, therefore, largely unnecessary and is treated only briefly below in Subsection 4.3.3.2.

The MBG scenario, on the other hand, receives closer attention with respect to transportation-related controls because it will require pipeline construction. MBG products will not be commingled with natural gas unless upgraded (methanized) to a heat value of 1000 Btu/scf. Since methanation is not posited here, existing pipelines will not serve to transport the MBG product. Land use controls related to pipeline construction are discussed in Subsection 4.3.3.3.

4.3.3.2 Railroad-Related Land Use Controls

Railroads in Texas come under the authority of the TRC and the Interstate Commerce Commission (ICC). Among the powers of the TRC is eminent domain, the right to condemn private property for public use. Under Texas statutes, the availability of rail service under the DF scenario is assured by the ability of railroad

companies to exercise, through authority of the TRC, the power of eminent domain. Railroad companies can acquire rights-of-way for spurs or industrial tracks through condemnation procedures.

Railroad transportation is, therefore, constrained only by the requirement that the hauler receive a certificate of public convenience and necessity prior to exercising the power of eminent domain. Once TRC issues the certificate, the hauler must meet no additional land use controls with respect to construction of necessary spur tracks.

4.3.3.3 Pipeline-Related Land Use Controls

Depending upon how an MBG pipeline is legally defined and classified under present Texas law, one of the two possible sets of land use controls discussed below will apply.

Lack of experience with MBG pipelines in Texas leaves considerable uncertainty concerning whether an MBG pipeline will be considered a common carrier or a contract carrier. Additional uncertainty exists concerning whether an MBG pipeline will be classified as a gas utility.

Alternative 1

If the pipeline is built by the MBG producer and operated by the producer for the exclusive purpose of transporting his own product (i.e. the pipeline is not engaged in transportation for hire) to one or more nonpublic, nonutility consumers, there is no apparent statutory basis for the TRC to assert authority over or to require a permit for the

pipeline builder or operator. Under this alternative, the land use controls in Table 4.3-3 will be effective.

Alternative 2

Alternative 2 includes any situation in which the TRC may assert its jurisdiction. Whether, or how, the TRC might assert such authority is presently open to question. Several possibilities are considered here.

The Texas Natural Resources Code provides in part that a person is a common carrier if it "owns, operates, or manages, wholly or partially, pipelines for the transportation for hire of coal in whatever form....." ²² Whether this statute was intended to include gasified coal is not presently known. The scanty legislative history of the statute is silent concerning this intent. If it is assumed, for the sake of argument, that gasified coal was intended to be included, it is clear that common carrier status will attach (unless the MBG producer owns his own pipeline and transports only his own gas).

Common carrier pipelines in Texas have the power of eminent domain. Exercise of this power relieves pipeline projects from many of the land use controls summarized in Table 4.3-3. "In the exercise of the power of eminent domain..., a common carrier may enter on and condemn the land, rights-of-way, easements and property of any person or corporation necessary for the construction, maintenance or operation of the common carrier pipeline." ²³ The power of eminent domain also relieves pipelines from the private controls in Table 4.3-3. Other controls are effected by §§ 111.020-111.022. Section 111.020 provides that common carriers "are entitled to lay, maintain, and operate [pipelines] along, across, or under

TABLE 4.3-3. LAND USE REGULATIONS UNDER ALTERNATIVE I

Federal Requirements	U.S. Army Corps of Engineers Galveston District	Permits for pipeline route, wetland and navigable waterway crossings, and interagency coordination
	U.S. Dept. of Transportation, State Dept. of Highways and Public Transportation	Permits to cross interstate highways
	U.S. Department of Transportation, Office of Pipeline Safety, with copy to TRC	Reports of leaks as specified in 49 CFR 191, Annual Operations Report, Plan for Inspection and Maintenance of Pipeline facili- ties and changes to such plans
State Requirements	State Dept. of Highways & Public Transportation	Permits to cross state roads
	Texas State General Land Office	Permits to cross state waters (in addition to Corps of Engi- neers Permit); includes all rivers and streams
	Texas Parks and Wildlife Depart- ment	Permits to cross wildlife refuges or parks, permit to cross Galveston Bay
	Texas Historical Commission	Historical and Archaeological Site Surveys
	Texas Department of Health	Portable and fixed sanitary facilities
	Texas Department of Water Resources	Permit for use of hydrostatic test water and permit for dis- charge of hydrostatic test water
(Continued)		

TABLE 4.3-3. LAND USE REGULATIONS UNDER ALTERNATIVE I (Continued)

Local Requirements	Individual County Governments	Permits to cross county roads, drainage structures, and public irrigation canals
	Individual City Governments	Permits to cross municipal streets
Private Requirements	Individual Railroad Companies	Permits to cross railroads
	Individual Land Owners	Granting of easements, permits to cross private roads and irrigation canals-filed with county
	Pipeline Companies	Permits to cross foreign pipelines

[public streams and highways]." This right may be exercised only where:

- There is no interference with traffic;
- The highway is promptly restored;
- The restoration is subject to supervision of the county commissioners court or other proper local authority; and
- Pipes are laid at least 15 feet from the highway unless otherwise approved by county authorities.

Section 111.021 confers upon common carriers the right to lay its pipe "under any railroad, railroad right-of-way, street railroad, or canal...."

Section 111.022, on the other hand, restricts the rights of common carriers with respect to incorporated or unincorporated cities or towns. Pipeline companies are required to receive express permission from the "governing body" of any city or town prior to laying pipes along or under streets or alleys.

Even if the MBG producer owns and operates his own pipeline, it may be possible for him to acquire common carrier status and the benefits of eminent domain power by filing with the TRC an agreement that "in consideration of the rights acquired, it becomes a common carrier subject to the duties and obligations inherent to such status." ²⁴

Assuming common carrier status under §111.002(5), an MBG pipeline must apply for and be issued a certificate of public convenience and necessity²⁵. Following notice and public hearing, TRC administers these certificates under §§111.302 and 111.305 of the Natural Resources Code.

Another possible source of TRC plenary authority is the Texas Public Utility Regulatory Act (PURA)²⁶. This authority is uncertain for two reasons. First, PURA references Article 6050 of the Texas statutes in defining "utility". Yet, Article 6050 speaks only in terms of natural gas. This leads to uncertainty because Article 1446C, §19(b) provides in part that "[t]he railroad commission shall have exclusive original jurisdiction over the rates and services of gas utilities distributing natural gas or synthetic natural gas in areas outside the limits of municipalities, and it shall also have exclusive original jurisdiction over the rates and services of pipelines transmitting, transporting, delivering, or selling natural gas or synthetic natural gas to gas utilities engaged in distributing such gas to the public." (Emphasis supplied.)

Synthetic natural gas is, however, nowhere defined. It could mean synthetic gas having Btu/unit characteristics similar to natural gas or it could mean synthetic gas which can be substituted for natural gas in terms of end use. If the former, MBG is not included. MBG does qualify under the latter interpretation. This ambiguity in the law may eventually be resolved either by the legislature or in the courts. Meanwhile, it leaves uncertain the question of whether, absent common carrier status, the TRC will exert jurisdiction over an MBG pipeline.

In the Texas Administrative Code (TAC), the TRC asserts authority over pipelines by requiring permits for their operation.²⁷ The procedural requirements associated with obtaining an operating permit are largely perfunctory and should not present regulatory delay. According to the TRC official responsible for issuing pipeline operating permits, satisfactory completion of TRC Forms T-4 or T-4C will automatically result in the granting of a permit. No public review is required. Common carrier status is obtained by completing the appropriate section of TRC Form T-4. In addition, the applicant must publish a notice that it has filed an application for a certificate of public convenience and necessity in a newspaper of general circulation in each county in which the project will be located. The TRC then conducts public hearings in areas of the state along the prospective pipeline right-of-way. Also, if the applicant has not filed an organization report with the TRC, it must file TRC Form P-5.

To exercise a right of eminent domain and condemn lands, easements, or rights-of-way within the State of Texas, a developer must follow the procedures set forth in Title 42, Articles 3264-3271, Vernon's Texas Civil Statutes. Exercising the right of eminent domain is a judicial function vested in the county judge within each county in which a project is to be located. Classification as a common carrier by the TRC does not automatically confer eminent domain powers, but creates a presumption in the county courts-at-law to that effect.

4.3.4 Controls Associated with New Industrial Facilities

4.3.4.1 Background

Local land use and environmental controls are largely beyond the scope of this study. Two programs that create more or less uniform local controls do, however, deserve some attention. These programs are the:

- National Flood Insurance Program (NFIP) administered in Texas by county and municipal governments and by water supply or levee districts and coordinated by the Texas Department of Water Resources; and
- Coastal Zone Management Program, administered by the Texas Energy and Natural Resources Advisory Council.

The NFIP has been implemented principally by authorizing local government entities to impose land use controls and permitting requirements on new construction in the 100-year floodplain. The Coastal Program is essentially a plan coordinating existing state resource agency efforts in the coastal zone. It is not strictly a land use control program although land use controls come into play as various agencies effect environmental policies in the coastal zone.

These programs are outlined briefly in Subsections 4.3.4.2 and 4.3.4.3.

4.3.4.2 National Flood Insurance Program

The National Flood Insurance Program (NFIP) established by the National Flood Insurance Act of 1968 (NFIA) provides for federally subsidized flood insurance to participating communities. The principal requirement for community participation is the establishment of satisfactory land use controls to regulate development within flood-prone areas.

The NFIA provides that the federal government will identify flood-prone communities, delineate special flood hazard areas, and provide more detailed flood data for them. As additional data are supplied, communities must adopt stricter land use regulations. The Federal Insurance Administration, now a part of the Federal Emergency Management Agency (FEMA), administers the program.

Several federal agencies, including the Army Corps of Engineers, Soil Conservation Service, Bureau of Reclamation, and the United States Geological Survey, have contributed to flood hazard mapping (delineation of the 100-year floodplain) and provided more detailed maps under Phase II of NFIP. These detailed maps are products of flood insurance rate studies. The maps show not only the 100-year floodplain, but also high water profiles within that floodplain. The 500-year floodplain is also delineated.

Because most eligible communities chose not to participate in the original program, Congress amended the NFIA in 1973. The Flood Disaster Protection Act of 1973 established strict sanctions for nonparticipating areas:

- After July 1, 1975, no federal assistance will be granted for the acquisition of or construction on property within identified flood-prone areas, unless the community in which such area is located participates in the NFIP. In order to participate, a community must adopt land use regulations consistent with federal criteria;
- Banks and savings and loan institutions subject to federal supervision, regulation, or insurance--virtually all financial institutions--are prohibited from making, increasing, extending, or renewing any loans secured by improved real estate in an area identified as having special flood hazards, unless the community in which the area is located is participating in the NFIP.

In Texas, the NFIP is coordinated by the Department of Water Resources under authority of the Flood Control and Insurance Act.²⁸ The state law authorizes administration of the program by counties, incorporated areas, and water supply and levee districts and empowers them to regulate development within their jurisdictional boundaries. Local administrative bodies must adopt provisions designating an official who will approve or disapprove permit applications for new construction consistent with the entity's flood program.

To qualify for the NFIP, flood-prone communities must adopt land use controls consistent with federal criteria.²⁹ These regulations state that "the minimum requirements governing the adequacy of the land use and control measures for flood-prone areas adopted by a particular community depend on the amount of technical data formally provided to the community by the FIA (now FEMA). Depending upon the specified amount of data, the minimum standards in Table 4.3-4 apply.

Participation in the NFIP in Texas is summarized in Table 4.3-5. Some 421 entities are participating in the emergency program and 275 are participating in the regular program. Many entities presently participating in the program are located in the Texas coastal zone or the lignite belt. Accordingly, it is expected that the program will affect the siting of new industrial facilities related to lignite development.

Moreover, provisions of the NFIP concerning disturbance of existing drainage in riverine floodplains may become important with respect to the surface mine itself. Surface mining operations in a floodway, for example, would require the mine operator to develop a special plan to mitigate flood hazard for the duration of the disturbance. Reclamation plans would have to include an acceptable program for restoring the floodway once mining ended.

Each participating entity must pass its own ordinance or have the local court issue an order to initiate local controls authorized by state law. There are, therefore, no uniform standards or procedural requirements under this program. Most entities, however, rely in differing degrees on model ordinances or model court orders published by the Texas

TABLE 4.3-4. MINIMUM LAND USE CONTROLS UNDER THE NFIP

Amount of Data Developed By FIA (Now FEMA)	Minimum Standards
I. - Special flood hazard areas not yet defined; - No water surface elevation data; and/or - Insufficient data to identify the floodway or coastal high hazard area.	- Require building permits for all proposed construction; - Review all building permit applications for new construction to determine whether proposed building sites will be reasonably safe from flooding; - Review subdivision and development proposals to assure that they are consistent with the need to minimize flood damage; <u>that all public utilities and facilities are located, elevated, and constructed to minimize or eliminate flood damage;</u> and that adequate drainage is provided; and - Require new or replacement water supply systems and/or sanitary sewage systems to be designed to minimize or eliminate infiltration of flood waters into the systems and discharges from the systems into flood waters, and require on-site waste disposal systems to be located in a manner that will avoid impairment and contamination during flooding.
II. - Special flood hazard areas identified; - No water surface elevation data; and - Insufficient data to identify the floodway or coastal high hazard area.	- Adapt land use control measures at least for all identified flood hazard areas (take into account floodplain management programs in adjacent communities). These controls must take precedence over any conflicting laws, ordinances, or codes;

(Continued)

TABLE 4.3-4. MINIMUM LAND USE CONTROLS UNDER THE NFIP (Continued)

Amount of Data Developed By FIA (Now FEMA)	Minimum Standards
III. - Special flood hazard areas identified; - Water surface elevation data for the 100-year floodplain; and - Insufficient data to identify the floodway or coastal high hazard area.	- Meet the first, third, and fourth requirements in I; - Review building permit applications for major repairs in special flood hazard areas to determine that the proposed repair uses materials that are resistant to flood damage and methods that will minimize such damage; - Review building permit applications for new construction or substantial improvements within special flood hazard areas to assure that the proposed construction (including prefabricated and mobile homes) is protected against flood damage; is designed and anchored to prevent flotation, collapse, or lateral movement; and uses construction materials that are resistant to flood damage and methods that will minimize such damage. Adopt land use control measures that: - Meet all the requirements under II; - Require new construction or substantial improvements of residential structures within special flood hazard areas to have the lowest floor (including the basement) elevated to or above the level of the 100-year flood; - Require new construction or substantial improvements of non-residential structures within special flood hazard areas to have the lowest floor (including the basement) elevated

(Continued)

TABLE 4.3-4. MINIMUM LAND USE CONTROLS UNDER THE NFIP (Continued)

Amount of Data Developed By FIA (Now FEMA)	Minimum Standards
IV. - Special flood hazard areas in <u>riverine floodplain</u> identified; - Water surface elevation data for the 100-year floodplain; - Floodway identified.	to or above the level of the 100-year flood or, along with utility and sanitary facilities, to be flood-proofed up to this level; and - In riverine situations, provide that until a floodway has been designated, no use, including landfill, may be permitted within special flood hazard areas unless the applicant for the use has demonstrated that the proposed use, when combined with all other existing and antici- pated uses, will not increase the water surface elevation of the 100-year flood more than one foot at any point. Adopt land use control measures that: - Meet all the requirements under II; - Meet the second and third requirements under III; - Designate a floodway for passage of the water of the 100-year flood. Selection must be based on the principle that the area chosen must be designed to carry the waters of the 100-year flood without increasing the water surface elevation of the flood more than one foot at any point; - Provide that existing nonconforming uses in the floodway will not be expanded but may be modified, altered, or repaired to incorporate flood-proofing measures, provided that such measures do not raise the level of the 100- year flood; and

(Continued)

TABLE 4.3-4. MINIMUM LAND USE CONTROLS UNDER THE NFIP (Continued)

Amount of Data Developed By FIA (Now FEMA)	Minimum Standards
V. - Special flood hazard areas in <u>coastal</u> floodplain identified; - Water surface elevation data for the 100-year floodplain; - Coastal high hazard area identified.	- Prohibit fill or encroachments within the designated floodway that would impair its ability to carry and discharge the waters resulting from the 100-year flood, except where the effect on flood heights is fully offset by stream improvements. Adopt land use control measures that: - Meet all the requirements under II; - Meet the second and third requirements under III; - Provide that existing uses located on land below the elevation of the 100-year flood in the coastal high hazard area will not be expanded; and - Provide that no land below the level of the 100-year flood in the coastal high hazard area may be developed unless the new construction or substantial improvement i) is located landward of the reach of the mean high tide, ii) is elevated on adequately anchored piles or columns to a lowest floor level at or above the 100-year flood level and securely anchored to such piles or columns, and iii) has no basement and has the space below the lowest floor free of obstructions.

TABLE 4.3-5. PARTICIPATING ENTITIES--NATIONAL FLOOD
INSURANCE PROGRAM STATE OF TEXAS

	Mapped	Not Mapped	Total
Emergency Program:			
Cities	339	11	350
Counties	61	4	65
Special Purpose Districts	5	1	6
Total			421
Regular Program:			
Cities			254
Counties			20
Special Purpose Districts			1
Total			275
Total in Flood Program			696
Designated Flood Prone And Not Participating:			
Cities	320	49	
Counties	71	98	
Total	391	147	

Department of Water Resources. In general, the following provisions must be included:

- Designation of a floodplain administrator (frequently a County Judge);
- Adoption by reference of Flood Hazard Boundary Maps (published by FEMA);
- A general designation of lands to which the order or ordinance applies (e.g. "areas subject to flooding");
- Permit application and review requirements;
- General and specific standards;
- Mobile home requirements;
- Standards for subdivision proposals; and
- Permit compliance certification requirements.

The ordinance or order must also include authorization for promulgation of forms and establishment of fees by the local government entity. Finally, there must be a provision providing for enforcement and penalties.

4.3.4.3 The Coastal Zone Management Program

The Coastal Zone Management Act of 1972 (CZMA)³⁰, as amended in 1976,³¹ provides coastal states assistance in developing and implementing programs for managing their coastal

areas. The Office of Coastal Zone Management (OCZM) in the Department of Commerce administers the Act. The OCZM has promulgated guidelines and requirements for state program development.³² The proposed Texas Coastal Program (TCP) is not strictly a land use control program. It is included in Section 4.3 because its goal is protection of coastal lands and, more generally, coastal resources and environmental values.

In order to gain program approval the State must develop a program that achieves the following:

- Identifies and examines coastal resources recognized in the CZMA as requiring management or protection by the state;
- Reconsiders present policies or develops new policies to manage these resources;
- Determines specific uses and geographic areas subject to the program based on identified coastal concerns, resource capability and suitability analyses, socioeconomic considerations, and public preferences;
- Identifies inland and seaward areas subject to management;
- Provides for consideration of the national interest in planning sites for facilities of more than local significance; and

- Includes sufficient legal authority and organizational structure to implement the program and insure conformance.

Up to four annual grants were made available to states to develop their own coastal management programs.³³ Participation is completely voluntary and no federal sanctions exist for noncompliance. States actively developing programs may be eligible for additional grants once the basic four are exhausted.³⁴

Texas received such a special grant in September, 1979. Once complete, the state program is submitted for federal approval.³⁵ Texas anticipates program approval by Spring, 1981. Once approved, Texas will qualify for federal matching funds for implementation and administration of the coastal management program.

Essentially, the TCP is a coordination effort under the auspices of the Texas Energy and Natural Resources Advisory Council (TENRAC) intended to clarify and improve existing relationships among state entities and with the federal government. The TCP seeks to upgrade the coastal management process without developing a new regulatory program or agency for regulating coastal activities. The principal state entities are the following: Texas Air Control Board; Texas Antiquities Committee; General Land Office/School Land Board; Texas Department of Health; Texas Parks and Wildlife Department; Texas Railroad Commission; Texas Department of Water Resources; State Department of Highways and Public Transportation; Department of Public Safety; Texas Coastal and Marine Council; Budget

and Planning Office; Bureau of Economic Geology; Office of the Attorney General; and Texas Energy and Natural Resources Advisory Council.

In general, the TCP finds acceptable existing management of coastal resources under the jurisdictions of these 14 entities. The TCP identifies only one significant management gap: the lack of a clearly enforceable mechanism for adequate management of privately-owned coastal saltwater wetlands and submerged lands not under the jurisdiction of the General Land Office/School Land Board. These nonjurisdictional areas constitute about 85 percent of the state's wetlands.

Although several state agencies presently provide comments to the U.S. Army Corps of Engineers for consideration in permit decisions regarding uses proposed for these areas, there is no readily enforceable means of reviewing such actions. To remedy this situation, a series of four draft Memoranda of Understanding (MOU) and two sets of proposed rules have been drafted among various state agencies now involved in the COE permitting processes. These documents and rules do not establish land use controls for privately-owned wetlands. They take a performance standard approach which seeks to balance the need for future development and the need to minimize the loss of wetlands. No additional permits, certifications, or approvals are required.

State regulatory authority over activities in the coastal area is exercised principally through permit, licensing, and certification systems. Agencies must apply state resource policies that they are authorized by law to consider in granting

approval of proposed activities in the coastal zone, even in the absence of an approved coastal management program. The TCP merely underscores the significance of applying these procedures, discussed in various other sections of this report, in the coastal zone. Those land uses in the coastal areas for which state agency approval is legally required, and which are, therefore, considered to be within the TCP are summarized in Table 4.3-6.

It should be noted that a number of the programs found in Table 4.3-6 are discussed in other sections of this report. To the extent that the activities described in those sections take place in the coastal zone, they are formally under the TCP. In the context of this subsection, it should be noted that as many as 17 of the 29 programs may be involved in siting, building, and operating new industrial facilities. While the TCP imposes no additional permitting or procedural requirements, these activities bring new industrial facilities within the TCP.

Two final points are important. In order to secure federal approval, the TCP must include an inventory of areas of particular concern. Guidelines for the priority of land uses within those areas must be established.³⁶ In addition to these areas where industrial siting would be disfavored, Texas recognizes areas particularly suitable for industrial development.

A second point worth considering is that the CZMA requires states to explain how their programs assume that local land and water use regulations within the coastal zone do not unreasonably restrict or exclude uses of regional benefit. These uses are defined in the TCP as follows:

TABLE 4.3-6. USES AND ACTIVITIES SUBJECT TO MANAGEMENT

USE OR ACTIVITY SUBJECT TO MANAGEMENT	METHOD OF REGULATION	AGENCY	STATUTORY AUTHORITY	REGULATION
1. Water Appropriation and Supply	Water Appropriation Permit	TDWR	Texas Water Code 11.121, 11.124, 11.134, 11.147	TDWR 156.02.35.001
2. Discharges in Water Point Source	Permit	TDWR	Texas Water Code Chapter 26	Texas Water Quality Standards
Non-Point Source	Permit	TDWR	Texas Water Code 5.131, 5.132	TDWR Rule 156.25.01.004, 156.25.25.001
Commercial Swine	Rules and/Permit (IA)*	TDWR	Texas Water Code 5.131, 5.132	TDWR Rule 156.24.05.003-.011
Meat Processing	Rules and Permit	TDWR	Texas Water Code 5.131, 5.132	TDWR Rule 156.24.10.003-.005
3. Sewage Facilities	"Orders for Control" Permits (IA)	TDWR/TDM	Tx. Rev. Civ. Stat. Ann. Art. 4477-1 Sec. 5(a)	TDM Construction Standards
4. Industrial and Municipal Solid Waste	Permit	TDWR/TDM	Tx. Ind. Solid Waste Act Tx. Rev. Civ. Stat. Ann. Art. 4477-7	TDWR 156.22.001.002 and Industrial Solid Waste Management Technical Guides TDM 301.02.01.005 and Municipal Solid Waste Management Regulations
5. Oil, Gas, and Geothermal Resource Activity	Rules and Permits	RRC/SLB	Texas Natural Resource Code 89.202(a)(8), 86.042(8), 141.071(2), Tx. Water Code 27.031	RRC Rules 051.02.02.046, 051.02.02.005- .015; SLB 135.16.03.004-.009
6. Geophysical and Other Surveys	Permit	GLO	Tex. Nat. Res. Code 31.101-.108	GLO 126.16.01.005, .007-.008, .011
7. Sand Gravel Washing	Rules and/Permit (IA)	TDWR	Texas Water Code Sec. 5.131, 5.132	TDWR Rule 156.24.15.003-.006
8. Mineral Leasing	Leases and Management Guidelines	SLB	Tex. Nat. Res. Code 34.051, 52.011, 141.073	SLB Rule 135.16.03.004, .006-.007, .009
9. Pollution in Oil and Gas Operations	Rules and/Permit (IA)	RRC	Tex. Nat. Res. Code Sec. 91.101	RRC Rule 051.02.02.008
10. Hazardous Substance and Oil Spills	Contingency Plan/ Notification	TDWR	Texas Water Code 26.261, <u>et seq.</u> and 26.039	Contingency Plan
11. Construction and Activity on Coastal Public Land	Easements	SLB	Tex. Nat. Res. Code Chapter 33	SLB Rule 135.18.01.003
12. Dredge Spoil	Rule and Policies	TPWD	P&W Code 11.011, 11.033, 12.001	TPWD Rules 127.30.01.001, 127.30.11.001, 127.30.13.001
13. Removal of Commercial Marl, Sand, Gravel, Shell and Mudshell	Permit	TPWD	P&W Code Chapter 86	TPWD Rules 127.30.04.002, .005-.006
14. Discharge of Dredge and Fill Materials	Memorandum of Understanding	TDWR/RRC/ TDM/GLO	Texas Water Code Chapter 26 Tex. Nat. Res. Code Section 91.101	To Be Adopted
15. Wetlands Acquisition	Certification	GLO/TPWD	Tex. Nat. Res. Code Sec. 33.231, <u>et seq.</u>	GLO 126.30.04.002
16. Activities on the Gulf Intracoastal Waterway	Sponsorship	SDNPT	V.A.C.S. Art. 5415e-2	(Statute) V.A.C.S. Art. 5415e-2
17. Commercial and Sport Fishing	Permits/Licenses	TPWD	P&W Code Sec. 61.201 and Chapters 43, 47, 51, 66, 76-78, 81	By reference only
18. Beach Access and Recreation	Rules	AG; GLO/SLB	Tex. Nat. Res. Code sec. 61.011-.024	SLB Rule 135.18.01.003 (and the Code)
19. Mobile Beach Business	Permit	TPWD	Tex. Nat. Res. Code 61.161-.177	TPWD Rules 127.20.04.001-.004
20. Beach Cleaning and Maintenance	Rules	TPWD	Tex. Nat. Res. Code 61.061-.083	TPWD Rules 127.50.04.006-.014
21. Dune Protection	Regulations and/Permit (IA)	GLO	Tex. Nat. Res. Code 63.001, <u>et seq.</u>	GLO Rules 126.30.03.004, 126.16.01.005
22. Floodplain Construction	Flood Hazard Guidelines	Exec. Order/ GLO	Exec. Order DB No. 34-A and V.A.C.S. art. 6889-7	TDWR Guidelines, TDWR Rule 156.10.10.001(a), And Federal Regulations
23. Construction of Mobile Homes	Standards and Requirements	TOLS	Tx. Rev. Civ. Stat. Ann. Art. 5221f	TOLS Standards
24. Groundwater Extraction	Permit (IA)	Hou-Gal CSD	64th Leg. Acts, Ch. 284	HGCSD Rule 7.1-7.20, TDWR Ind. Solid Waste Management Guides
25. Erosion Control	Regulations	GLO/SLB	Tex. Nat. Res. Code 32.062, Ch. 33, 63	SLB Rule 135.18.01.003; GLO 126.30.03.004
26. Easements on State Land	Rights-of-Way, Easements	GLO/SLB	Tex. Nat. Res. Code sec. 33.101-.134, 34.051 and 51.291	GLO Rule 126.18.02.002
27. Surface Mining	Permit	RRC	Tex. Nat. Res. Code Ch. 131	RRC Rule 051.07.03.002, .109, .304
28. Air Emissions	Const. and Op. Permits	TACB	Tx. Rev. Civ. Stat. Ann. Art. 4477-5	TACB Rule 131.08.00.001, <u>et seq.</u>
29. Cultural Resource	Permit	TAC	Tex. Nat. Res. Code Ch. 191	TAC Rule 355.01.00.005-.007

* (IA) If Applicable

- Transportation facilities including roads, railroads, ports, navigation districts, waterways, and airports;
- Sport and commercial fisheries;
- Recreation and wildlife management;
- Pipelines for oil and gas;
- Underground storage of gas;
- Power plants and transmission lines;
- Regional waste treatment plants; and
- Energy facilities.

A new industrial facility, such as hypothesized under the DF scenario, is not among these uses. It is of a nature sufficiently similar to a number of these uses, however, that programs insuring ample sites for the latter will tend to open sites to industrial facilities as well.

In general, the TCP merely coordinates the ongoing efforts of state resource agencies and related agencies within the setting of the coastal zone. The TCP imposes no additional layers of bureaucracy or permitting. The attitude underlying the TCP is one of accommodation and balancing of competing interests in the coastal zone. There are no particular impacts caused by the TCP other than possible facilitation of efforts to find appropriate.

or other activities (such as pipeline or rail spur construction) under either scenario.

Footnotes - Section 4.3

- ¹ 30 USC 1201, as amended.
- ² 33 USC 1251, et seq.
- ³ 42 USC 7401, et seq.
- ⁴ 42 USC 6901, et seq.
- ⁵ 33 USC 1288, 1313(c)(e)
- ⁶ 16 USC 1531, et seq.
- ⁷ 16 USC 661, et seq.
- ⁸ 16 USC 470, et seq.
- ⁹ Part 815; TR 051.07.04.325-.328.
- ¹⁰ Part 816; TR .330-.422.
- ¹¹ TR .327(a).
- ¹² 16 USC 1531, et seq.
- ¹³ TR .335-.338.
- ¹⁴ TR .339-.355.
- ¹⁵ TR .357-.362.
- ¹⁶ TR .363-.366.
- ¹⁷ TR .368-.378.
- ¹⁸ TR .379.
- ¹⁹ TR .380.
- ²⁰ TR .384-.389.
- ²¹ TR .390-.396.
- ²² Vernon's Tx. Nat. Res. Code §111.002(5).
- ²³ Vernon's Tx. Nat. Res. Code §111.019(b).
- ²⁴ Vernon's Tx. Nat. Res. Code §111,020(d).
- ²⁵ Vernon's Tx. Nat. Res. Code §111.301.
- ²⁶ Vernon's Ann. Civ. St. art. 1446(c).
- ²⁷ 16 TAC 3.65.
- ²⁸ Vernon's Tx. Water Code §§16.311-16.319.
- ²⁹ 44 CFR Parts 59-79.
- ³⁰ P.L. 92-583.

31 P.L. 94-370
32 15 CFR Part 923
33 CZMA §305
34 CZMA §305(d)
35 CZMA §306
36 15 CFR 923.21

4.4 Water Quality Controls

4.4.1 Introduction

Pursuant to the Federal Water Pollution Control Act (now the Clean Water Act) and the Safe Drinking Water Act, the U.S. Environmental Protection Agency has developed extensive programs to protect the quality of the Nation's ground and surface waters. The Federal Water Pollution Control Act Amendments of 1972 established the following basic water quality goals and policies for the United States:

- The discharge of pollutants into navigable waters should be eliminated by 1985;
- An interim goal of water quality providing for recreation in and out of water and for the protection and propagation of fish, shellfish, and wildlife should be achieved by 1983; and
- The discharge of pollutants in toxic amounts should be prohibited.

The Safe Drinking Water Act of 1974 (SDWA) seeks to protect drinking water supplies by establishing National Primary and Secondary Standards as maximum contaminant levels. The emphasis of the legislation is on regulation of drinking water supply quality and delivery systems, but it also includes programs to protect underground sources of drinking water from future contamination.

Texas, acting by and through the Texas Department of Water Resources, also administers a waste discharge permit program designed to protect surface and underground water quality.

This section describes the following federal water quality programs and their applicability to the DF and MBG scenarios:

- NPDES program;
- Underground Injection Control (UIC) program;
- Ocean Dumping program; and
- Oil Spill Plan approval.

In addition, this section will discuss the Texas waste discharge program and its applicability to the two scenarios.

4.4.2 Federal Water Quality Programs

4.4.2.1 National Pollutant Discharge Elimination System

The Federal Water Pollution Control Act of 1972, as amended by the Clean Water Act of 1977, prohibits the discharge of pollutants into the navigable waters of the United States unless authorized by a permit issued by the Regional Administrator of EPA [33 U.S.C. §1411]. The permit program, designated the National Pollutant Discharge Elimination System (NPDES) provides that EPA permitting authority can be delegated to state regulatory agencies meeting specified federal criteria. EPA retains oversight and veto authority, however, even if a state has an approved NPDES program. Texas does not administer an EPA-

approved NPDES program, although Texas has a water pollution control program established under state law. Texas is required to certify EPA's draft NPDES permits as being consistent with (at least as stringent as) its water quality regulations.

Functions of the NPDES permit stipulated by the Act are as follows:

- Limit discharges of effluents based on national technology-based guidelines and, where necessary, water quality standards;
- Impose schedules of compliance for the permittee to complete construction or to install new pollution control technology; and
- Require permittees to monitor their discharges and report results and violations to the permitting agency.

Technology-Based Limits

NPDES permits are written by EPA regional offices, or by environmental agencies of states with delegated NPDES authority. The parameters and the quantities allowed in industrial discharges are selected based on effluent guidelines prepared for classes and categories of point sources, and published by EPA's Effluent Guidelines Division (EGD) in Washington, D.C. EGD studies the technologies used by and available to 27 industrial categories and selects effluent quantities and qualities attainable. These studies go into the "rulemaking

package" prerequisite to proposal of effluent guidelines in the Federal Register.

Technology-based effluent limitations are of essentially four types:

- General effluent limitations (BPT, BAT, BCT) under Section 301 of the Act;
- New Source Performance Standards (NSPS) under Section 306;
- Toxic and pretreatment effluent standards under Section 307; and
- Thermal discharge standards under Sections 301, 306, and 317.

Sections 301, 306, 307, and 316 of the Act establish the economic and technical criteria which EPA must consider in promulgating effluent limitations guidelines (Table 4.4-1). The limitations are established for classes and categories of point sources (other than publicly-owned treatment works). The guidelines should articulate the economic and technical assumptions on which they are based. Individual point sources which deviate from assumptions on which the guidelines are based may file an application for a variance in the NPDES permit process.

Technology-based effluent limitations are discussed in greater detail below.

1) BPT - Best practicable control technology currently available was to be achieved by industry by July 1, 1977, and development of subsequent technology-based guidelines assume

TABLE 4.4-1. FACTORS RELEVANT TO NPDES EFFLUENT LIMITATIONS GUIDELINES

BPT (July 1, 1977)	BAT (July 1, 1984)	BCP (July 1, 1984)	NSPS	Toxics	Thermal Discharges
1. Degree of effluent reduction attainable through application of best practicable control technology currently available. 2. Total cost of technology application in relation to effluent reduction benefits. 3. Age of equipment and facilities. 4. Process employed. 5. Engineering aspects of the application of various types of control techniques. 6. Process changes. 7. Non-water quality environmental impact (including energy requirements).	1. Degree of effluent reduction economically achievable through the application of best control measures and practices achievable, including treatment techniques, process and procedure innovations, operating methods, and other alternatives. 2. Age of equipment and facilities. 3. Process employed. 4. Engineering aspects of the application of various types of control techniques. 5. Process changes. 6. Non-water quality environmental impact (including energy requirements).	1. Degree of effluent reduction attainable through application of best conventional pollutant control technology. 2. Reasonableness of relationship between costs of attaining reduction in effluents and effluent reduction benefits derived. 3. Comparison of cost and level of reduction of pollutants from discharge from publicly owned treatment works to cost and level of reduction of such pollutants from class or category of industrial sources. 4. Age of equipment and facilities. 5. Process employed. 6. Engineering aspects of the application of various types of control techniques. 7. Process changes. 8. Non-water quality environmental impact (including energy requirements).	1. Standard of control which reflects degree of effluent reduction achievable through application of best available demonstrated control technology, processes, operating methods, or other alternatives, including, where applicable, a standard permitting no discharge. 2. Cost of achieving such effluent reduction. 3. Non-water quality environmental impact. 4. Energy requirements. 5. Distinctions among classes, types and sizes of new sources. 6. Process employed.	1. Degree of reduction achievable through application of BAT or more stringent limitations. 2. Toxicity, persistence, and degradability of pollutant. 3. Usual or potential presence of affected organisms in waters. 4. Importance of affected organisms. 5. Nature and extent of effect of toxic pollutant on organisms. 6. Extent to which effective control is being or may be achieved under other regulatory authority.	1. Degree of reduction achievable through application of BPT, BAT, BCT, or NSPS (as applicable). 2. Location, design, construction and capacity of cooling water intake structures which reflect best technology available for minimizing adverse environmental impact. 3. Thermal component which will assure protection and propagation of balanced, indigenous population of shellfish, fish and wildlife.

compliance with BPT guidelines. Selection of BPT parameters and quantities was based on samples taken from industries demonstrating "average of the best" wastewater treatment and usually emphasized conventional pollutants.¹ Industry sampling was followed by EPA rulemaking package preparation, guidelines proposal, public comment, guideline promulgation, and court challenges by affected third parties.

2) BAT - Best available technology economically achievable is to be in place by July 1, 1984. Development of BAT guidelines is following the same procedure as BPT, but the emphasis is now on toxic pollutants which are defined by the Consent Decree resulting from a lawsuit filed by the Natural Resources Defense Council against EPA in the 1970's (NRDC V. Train). Whereas BPT is average of the best technology, BAT is to be "best of the best". The economic evaluation of potential BAT's is performed by EPA and involves applying the cost of the technology to a sample of the industry which does not use that or an equivalent technology to determine what portion of the industry will be severely impacted as a result of the expense of implementing the technology.

The schedule for BAT effluent guidelines development is shown in Table 4.4-2.

3) BCT - Best conventional technology is capable of better removal of conventional pollutants than BPT and is to be met by July 1, 1984. BCT is developed in conjunction with BAT.

4) NSPS - New source performance standards are developed, proposed, and promulgated with BAT and are as strict or stricter than BAT. They apply to any industrial facility which commences construction after the date of proposal of NSPS

TABLE 4.4-2. BAT EFFLUENT GUIDELINES DEVELOPMENT SCHEDULE¹

	Proposal	End Public Comment	Promulgation
Petroleum Refining	12/79	2/80	6/80 ²
Steam Electric	5/80	7/80	12/80 ³
Coal Mining	9/80	11/80	3/81
Ore Mining and Dressing	9/80	11/80	4/81
Gasohol Fuels	1981	-	-
Synthetic Fuels	1982-83	-	-

¹ These schedules are somewhat flexible and are often extended.

² Petroleum refining guidelines not out as of 9/80.

³ Steam-Electric is behind schedule.

for the particular industrial classification (Table 4.4-2). NSPS also emphasize toxic pollutants and are to be best available demonstrated control technology, processes, operating methods or other alternatives. Generally in energy industries, NSPS are not much more difficult to achieve than BAT and are often equal to BAT.

5) Toxic Effluent Standards - The 1977 Amendments emphasize toxic pollution control, and BAT, NSPS, and pretreatment standards (discussed below incorporated in NPDES permits) are the control mechanisms. The base list of toxic or priority pollutants resulted from the NRDC v. Train Consent Decree which listed 65 families of pollutants. These families include a list of 129 pollutants. If these pollutants were found in the discharges of an industry sector in treatable concentrations, EPA was to have published BAT effluent limitations for the

pollutants by July, 1980, and these were to be met by industry by July, 1984. Some energy industry sources have not met this schedule; NPDES permit applicants in those industries will be required to comply no later than three years after promulgation of effluent guidelines.

6) Pretreatment Standards - Also included in an EPA development document are Pretreatment Standards for indirect discharges (discharges to a publicly-owned treatment works or POTW's). POTW's can generally handle conventional pollutants, so pretreatment standards are primarily concerned with toxic pollutants or pollutants which will upset the treatment plant. No permit is required by the indirect discharger, but the POTW must ensure compliance or provide treatment for the toxic pollutants.

7) Thermal Discharges - Thermal discharge standards must reflect the "best technology available for minimizing adverse environmental impacts" from categories of point sources with thermal components. Section 3.6, however, also allows a NPDES applicant to demonstrate to the EPA Administrator that the thermal effluent limitations are more stringent than necessary to assure the protection and propagation of shellfish, fish and wildlife in the body of water into which the effluent is being discharged. Under these circumstances, the Administrator may impose a less stringent thermal effluent limitation.

Water Quality-Related Limits

Although the 1972 Amendments relegated water quality-based limits to secondary importance, they may still impact the energy industry. BAT effluent limitations may become water quality-based because each state has the authority to adopt more stringent water quality based standards where there are data to support them. The Act and the Consent Decree require EPA to develop water quality criteria for 65 families of toxic pollutants. These criteria are to be maximum stream concentrations for protection of aquatic life and human health. The criteria will be developed as EPA has developed previous water quality criteria (based on LC₅₀ tests¹). Some differences may occur due to a new emphasis on consideration for varying conditions of hardness, salinity, etc.

Water quality standards are adopted by the states to suit water uses identified for particular stream segments. Each river in a state may have several (more than five) stream segments; therefore, state water quality standards may be lengthy documents. States use the EPA water quality criteria and water uses assigned to each stream segment to adopt equal or stricter water quality standards. Some states are now showing indication of down-grading water uses, presumably to increase the toxic pollutant standards which are often so low as to be expressed in micrograms per liter. EPA has the authority to override a state's selected standards and promulgate standards for the state, and it is threatening to do so to keep the current designated water uses.

¹LC₅₀ (Lethal Concentrations - 50%) - lowest pollutant concentration known to kill half of a sampling of selected aquatic species.

If state water quality standards are violated (or potentially violated) in a particular stream segment due to discharges which meet BAT, BCT, or NSPS, the permits are to be more stringent than BAT, BCT, or NSPS. Such stream segments are called water quality-limited (as opposed to effluent-limited) and the states must rank them as to severity and, starting with the most severe, develop waste load allocations. The allocations are performed by published EPA methods or EPA-approved methods such as water quality models. Models are mathematical simulations of aquatic systems which are usually computer-based and complex. Using mathematical simulation, total maximum daily loads (TMDLs) are established for each segment and each toxic pollutant. The sum of the pollutant loads entering the water quality-limited segment cannot exceed the TMDL and if a new discharger causes the TMDL to be exceeded, the proposed pollutant load must be reduced or reductions must be obtained from other dischargers.

NPDES Permitting Process

The EPA NPDES permitting process for new sources includes review of the application by EPA, compliance with NEPA requirements (EID, EA, EIS), state certification of the permit draft, public notice and hearing, response to public and state comments. Figure 4.4-1 illustrates the EPA NPDES permitting process.

Effluent limitations are enforced by incorporation into a discharger's NPDES permit. The limitations are generally those quantities specified for categories of industrial activities and are based on treatment technology requirements for types of pollutants (i.e., BAT for toxics and nonconventional pollutants; BCT for conventional pollutants).

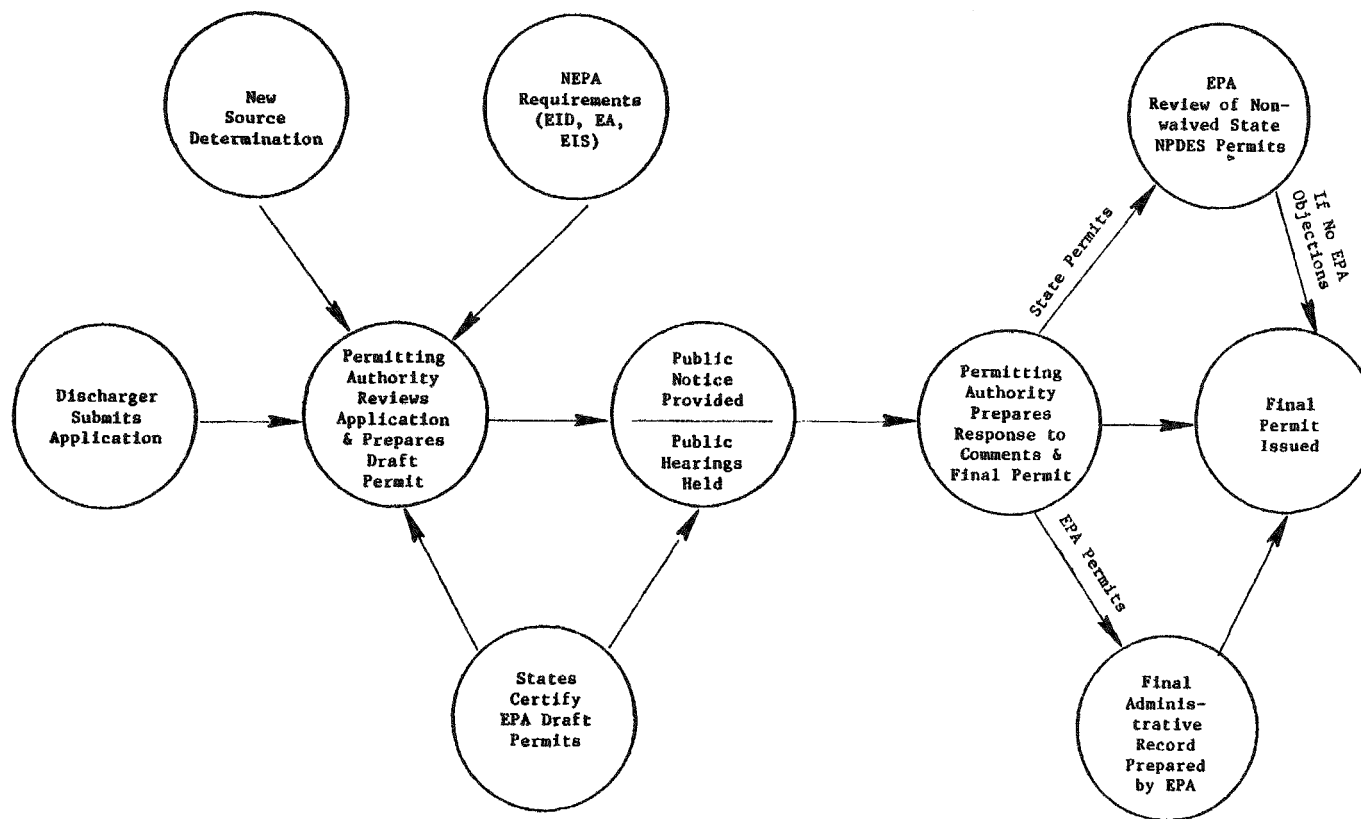


Figure 4.4-1. Basic EPA NPDES Permit Process

If EPA-promulgated effluent limitations guidelines are inapplicable, the permitting authority (EPA or the state) must impose limitations case-by-case in the NPDES process on the basis of the following factors:

- The appropriate technology for the category of point sources of which the applicant is a member;
- Any unique factors relating to the applicant; and
- Factors listed in Section 304 of the Clean Water Act (see Table 4.4-1).

In other words, for effluent parameters not covered by EPA-promulgated guidelines, the permitting authority makes a case-by-case assessment of the same factors considered by EPA in promulgating effluent limitations guidelines.

In addition, both the Clean Water Act and EPA regulations define certain criteria which may be considered by EPA in granting variances for conventional and nonconventional pollutants from effluent limitations and modifications to conditions of individual permits. These variances and modifications may be based on economic capability, water quality, "fundamentally different factors," use of innovative technology, and unnecessarily stringent thermal discharge limitations. The applicant must specifically apply for these variances and modifications and must sustain certain additional burdens of proof in the permitting process in order to obtain the exemption. No variances from effluent limitations on toxic pollutants are available.

Applicability to DF and MBG Scenarios

Both the DF and MBG scenarios will require new source NPDES permits from EPA for discharges from the lignite mine sites. Because the mine required for the MBG scenario is larger, its discharges will be more significant. The new lignite gasification facility postulated in the MBG scenario and the new industrial facilities postulated in the DF scenario will also require new source NPDES permits for their respective wastewater discharges.

The difference in the postulated location of the gasification plant and the new lignite-fired industrial facilities, however, may affect the effluent limitations applicable to each if water quality-limited stream segments are involved.

4.4.2.2 Underground Injection Control (UIC)

Introduction

The Safe Drinking Water Act of 1974 requires EPA to develop minimum requirements for state programs to protect underground drinking water sources. Pursuant to that mandate, EPA has promulgated National Interim Primary Drinking Water Regulations [40 C.F.R. Part 141] specifying maximum drinking water contaminant levels for organic and inorganic chemicals, turbidity, coliform bacteria, and certain radioactive elements. EPA has also promulgated National Secondary Drinking Water Regulations to control drinking water contaminants that primarily affect the aesthetic qualities relating to the public acceptance of drinking water. The Secondary Regulations are not federally enforceable, but are intended as guidelines for the states.

Also pursuant to that mandate, EPA has proposed and adopted regulations establishing minimum requirements for effective Underground Injection Control (UIC) programs. Regulations establishing criteria and standards (40 C.F.R. Part 146) for state UIC's were finalized June 24, 1980. Under Section 1422, the Administrator of EPA must list "each State for which in his judgment a State underground injection control program may be necessary to assure that underground injection will not endanger drinking water sources" and to establish by regulation a program for EPA administration of UIC programs in the absence of an approved program in a listed state. Because all states have been listed, all states must submit a UIC program within 270 days after the effective date of the criteria/standards rules (40 C.F.R. Part 146), which period may be extended by EPA for 270 days upon application by the state. During the interim period before EPA approval of a state UIC program, disposal of waste by underground injection is covered by RCRA regulations (see Section 4.7).

Implementation Framework

The UIC implementation framework is established by Section 122.31 et seq. of the EPA Consolidated Permit Regulations, issued in May, 1980. Effective no later than the date of EPA state program approval or the effective date of EPA regulations establishing the state program, any UIC program shall prohibit any underground injection or the construction of any disposal well, except as authorized by permit or rule.

The regulations require the Administrator to protect, except where specifically exempted, all aquifers or portions of aquifers which meet the definition of an "underground source of drinking water" (USDW):

[A]n "aquifer" or its portion:

- (a)(1) Which supplies drinking water for human consumption; or
- (2) In which the ground water contains fewer than 10,000 mg/l "total dissolved solids;" and
- (b) Which is not an "exempted" aquifer.

The proposed Part 146 criteria/standards regulations define an exempted aquifer as one which

- (a) Does not currently serve as a source of drinking water; and
- (b) Cannot and will not in the future serve as a source of drinking water because:
 - (1) It is mineral, oil, or geothermal energy producing;
 - (2) It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical; or
 - (3) It is so contaminated that it would be economically or technologically impractical to render the water fit for human consumption.

The UIC program regulates underground injections by five classes of wells. Table 4.4-3 summarizes the classes of wells and the prohibitions associated with each type.

The proposed standards for Class IV wells provided for a ban on the construction and operation of new Class IV wells, and a three-year phase-out of existing ones. In the May, 1980 UIC regulations, EPA expressly reserved the requirements for Class IV wells, other than those injecting hazardous wastes directly into a USDW. Section 122.36 of the UIC regulations banned the construction of any new Class IV well injecting hazardous waste directly into a USDW and provided for the closure of existing Class IV wells directly injecting hazardous waste into USDW's within six months following promulgation and approval of any state UIC program.

In the May, 1980 UIC regulations, EPA solicited public comments on two alternative approaches to the designation of USDW's which would expand the range of allowable Class IV practices. Option A would modify the definition of a USDW to decline to protect USDW's in areas adequately served by other sources. To justify this additional basis for exemption, the State Program Director could be required to consider the following factors:

- Present and future availability of alternative sources of drinking water;
- Future population growth and land use patterns in the area; and
- The expected growth in the demand for drinking water.

TABLE 4.4-3. CLASSIFICATION OF INJECTION WELLS
UNDER STATE UIC PROGRAMS

Class	Classification	Prohibitions
Class I	(1) Wells used by generators of hazardous waste or owners/operators of HWMF* to inject hazardous waste, other than Class IV wells. (2) Other industrial/municipal disposal wells which inject fluids beneath the lower most formation containing, w/in 1/4 ml. of the well bore, a USDW.**	No UIC authorization by permit or rule where: Class I well causes or allows movement of fluid into USDW.**
Class II	Wells which inject fluids: (1) Which are brought to the surface in connection with conventional oil or natural gas production; (2) For enhanced recovery of oil or natural gas; and (3) For storage of hydrocarbons which are liquid at standard temperature and pressure.	Where Class II well causes or allows movement of fluid into USDW.**
Class III	Wells which inject for extraction of minerals or energy, including: (1) Mining of sulfur by the Frasch process; (2) Solution mining of minerals; (3) In situ combustion of fossil fuel; and (4) Recovery of geothermal energy.	Where Class III well causes or allows movement of fluid into USDW.**
Class IV	Wells used by generators of hazardous wastes or of radioactive wastes, by owners or operators of HWMF* or by owners or operators of radioactive waste disposal sites to dispose of hazardous wastes or radioactive wastes into or above a formation which within one quarter mile of the well contains a USDW.**	Where Class IV well causes or allows movement of fluid containing any contaminant into USDW and presence of contaminant may cause violation of any primary drinking water regulation or which may adversely affect health of persons.
Class V	Injection wells not included in Classes I, II, III or IV.	Where Class V well causes or allows movement of fluid containing any contaminant into USDW and presence of contaminant may cause violation of any primary drinking water regulation or which may adversely affect health of persons.

*HWMF=Hazardous Waste Management Facilities

**USDW=Underground Source of Drinking Water

Under the revised definition, such wells would fall under Class I because they would inject into exempted aquifers, and injectors could apply for permits of up to ten years duration.

Option B is based on the rationale that injection or presence of contaminants in a USDW may not necessarily lead to drinking water supplies exceeding the primary drinking water standards or adverse effects on the health of persons. Option B entails a liberal approach to regulating Class IV wells if the applicant could demonstrate that the injection: (1) is environmentally the most acceptable method of disposal; and (2) would not contaminate the portion of the aquifer from which water is drawn for drinking. The applicant would have to demonstrate the following:

- Technology for safe disposal is not available, taking into account the costs;
- Injecting fluid will be less harmful than use of other available means; and
- Technology and other means will be employed to reduce volume and toxicity of waters.

Performance Standards/Criteria

The proposed performance standards and criteria for new Class I wells, which would include the types of disposal wells associated with industrial and gasification facilities, are as follows:

- Must be sited so that it injects into a strata which is below the deepest USDW in the area and has an overlying confining bed that is free of open faults or fractures within the area of review;
- Must be cased and cemented to prevent the upward migration of fluids into or between USDWs;
- Must inject fluids through tubing and packer set immediately above the injection zone; and
- Must have parts constructed of corrosion-resistant material, if parts come into contact with corrosive fluids.

In addition, the proposed regulations require that logs and other tests be conducted during the drilling and construction of new Class I wells and certain information concerning the injection formation be provided to the state UIC program director. The regulations also establish operating, monitoring, and reporting requirements as well as performance standards for abandonment of Class I wells.

Permit Procedures

Certain categories of injection wells may be authorized by general rules promulgated by a state administering an approved UIC program:

- Injection into existing Class I, II, and III wells may be authorized by rule for periods up to five years following state UIC program approval;
- Injection into existing Class I enhanced recovery and hydrocarbon storage wells may be authorized for the life of the well;
- Injection into existing Class IV wells injecting directly into a USDW may be authorized for a period of not more than six months following state UIC program approval; and
- Injection into Class V wells may be authorized indefinitely under certain conditions.

All new Class I, II, and III wells must be authorized by permits issued by the state (in an EPA-approved program) or by EPA (in an EPA-administered program) in accordance with minimum procedures established by the EPA Consolidated Permit Regulations (§§122.38 et seq.). These minimum procedures include an application accompanied by certain specified information; review by the state director or EPA Regional Administrator; public notice, hearing, and comment; and permit issuance, subject to various permit conditions.

Applicability

State or EPA UIC program requirements will be applicable to any scenario which contemplates disposal of process wastes by

underground injection. The unsettled state of EPA policy towards Class IV wells for injection of hazardous wastes negatively impacts both scenarios equally.

4.4.2.3 Ocean Dumping Permit

Introduction

The Marine Protection, Research, and Sanctuaries Act of 1972 is primarily concerned with regulating the transportation for dumping and the dumping of material into ocean waters. The Act incorporates the policy of the United States "to regulate the dumping of all types of materials into ocean waters and to prevent or strictly limit the dumping into ocean waters of any material which would adversely affect human health, welfare, or amenities, or the marine environment, ecological systems, or economic potentialities."

The purpose of the Act is to regulate the transportation by any person of material from the United States when that transportation is for the purpose of dumping the material into ocean waters.

"Ocean" or "ocean waters" means those waters of the open seas lying seaward of the baseline from which the territorial sea is measured, i.e. "the line of ordinary low water along that portion of the coast which is in direct contact with the open sea." This definition includes the waters of the territorial sea (extending seaward a distance of three miles), the contiguous zone, and the high seas beyond the zone. A distinction should be noted here between the geographic area included in the Marine Protection, Research, and Sanctuaries Act and that encompassed in the Clean Water Act. The latter's jurisdiction

covers point source pollution in navigable waters, which includes the territorial seas, contiguous zone, and ocean.

"Material" is defined as "matter of any kind or description, including, but not limited to, dredged material; solid waste; incinerator residue; garbage; sewage sludge; munitions; radiological, chemical, and biological warfare agents; radioactive materials; chemicals; biological and laboratory waste; wreck or discarded equipment; rock; sand; excavation debris; and industrial, municipal, agricultural, and other waste." Oil of any kind or in any form, including that mixed with wastes other than dredged spoil, shall constitute material only to the extent that it is taken on board a vessel or aircraft for the primary purpose of dumping.

"Dumping" means a disposition of material; and herein lies a distinction between the NPDES permit program and that of the Marine Protection, Research, and Sanctuaries Act. The NPDES program requires permits for the discharge of pollutants from any "point source" into waters of the United States. A point source is "any discernible, confined, and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock, concentrated animal feeding operation, vessel, or other floating craft, from which pollutants are or may be discharged." The purview of the Marine Protection, Research, and Sanctuaries Act apparently does not include pollution from point sources; rather, it regulates the transportation of material for the purpose of dumping in ocean waters.

Criteria

The criteria for the issuance of ocean disposal permits are considered under the environmental effects of the

proposed dumping operation, the need for ocean dumping, and the effect of the proposed action on aesthetic, recreational, and economic values and other uses of the ocean. In addition, no permit can be issued when the dumping would result in a violation of applicable water quality standards.

The environmental impact conditions are the first set of criteria which have to be satisfied. The proposed dumping must have no unacceptable adverse effects on human health, the marine environment and ecosystem, and no effects which would prohibit other uses of the ocean. Along with the satisfaction of these criteria, it must be demonstrated that: 1) there is a need for dumping, and no alternative means of disposal are available; 2) there are no unacceptable adverse effects on aesthetic, recreational, or economic values; and 3) there are no unacceptable adverse effects on other uses of the ocean such as commercial and recreational fishing, commercial navigation, or scientific research and study.

If the EPA Administrator determines that the material proposed for ocean dumping satisfies the environmental impact criteria, but not the other criteria, he may deny the permit. However, the regulations state that he may issue an interim permit if the material does not contain prohibited materials, if there is a need for dumping and no alternatives are available, and if the need for dumping is of greater significance to the public interest than the potential for adverse effects on aesthetic, recreational, economic, or other uses of the ocean. Similarly, the Administrator may also issue an interim permit even if the material proposed for dumping does not satisfy the environmental impact criteria, provided the subsequent regulations apply, as in the aforementioned case.

Applicability

If either the MBG or DF scenarios contemplate disposal of process wastes by ocean dumping, the facility owner/operator will have to obtain an ocean dumping permit. Given the proximity to the Gulf of the lignite-fired industrial facility posited in the DF scenario, it is more logical to expect that ocean dumping of wastes would be seriously considered as an alternative disposal method to land disposal for that scenario.

4.4.2.4 Oil Spill Approval

Introduction

According to Title 40 Code of Federal Regulations, Part 112, "owners or operators of onshore and offshore facilities ... that have discharged or, due to their location, could reasonably be expected to discharge oil in harmful quantities...into or upon the navigable waters of the United States or adjoining shorelines, shall prepare a Spill Prevention Control and Countermeasure Plan (SPCC). Such a plan shall be prepared within six months after the facility begins operations and shall be implemented as soon as possible, but not later than one year after the facility begins operations.

Preferred Standards and Guidelines

The SPCC Plan shall be a carefully thought-out plan, prepared in accordance with good engineering practices, and which has the full approval of management at a level with authority to commit the necessary resources. If the plan calls for additional facilities or procedures, methods, or equipment not yet fully operational, these items should be discussed in separate para-

graphs. The complete plan must include a discussion of the facilities conformance with the following appropriate guidelines:

- A facility which has experienced one or more spill events (discharges of oil into or upon navigable waters of the U. S. or adjoining shorelines in harmful quantities) 12 months prior to effective date of these regulations (March 26, 1976) should include a written description of each spill, corrective action taken, and plans for preventing recurrence.
- Where experience indicates a potential for equipment failure, the plan should include a prediction of the direction, rate of flow, and total quantity of oil which could be discharged from the facility as a result of failure.
- Appropriate containment and/or discretionary structures or equipment to prevent discharged oil from reaching a navigable watercourse should be provided.
- Where the preceding requirement is not practicable, the owner or operator must clearly demonstrate this; and provide a strong oil contingency plan and written commitment of manpower, equipment, and materials to control and remove any harmful quantity of discharged oil.

- The plan should include a discussion of conformance with: facility drainage (onshore); bulk storage tanks (onshore); facility transfer operations, pumping, and in-plant process (onshore); facility tank car and tank truck loading/unloading rack (onshore); oil drilling and workover facilities (onshore); oil drilling, production, or workover facilities (offshore); inspections and records; security (excluding oil production facilities); and personnel, training, and spill prevention procedure.

Amendments to a SPCC Plan may be initiated by the owners or operators, or the EPA Regional Administrator.

4.4.2.5 Emergency Plans in the Transportation of Gas by Pipeline

Part 192.615 of Title 49, regarding the formulation of emergency plans in the transportation of gas by pipeline, may apply to the construction and operation of a coal gasification pipeline. "Gas" in this part is defined as natural gas, flammable gas or gas which is toxic or corrosive.

According to Part 192.615, each operator shall establish written procedures to minimize hazard resulting from a gas pipeline emergency. These procedures must provide for:

- The receipt, identification, and classification of notices of events which require immediate response by the operator.

- Establishment and maintenance of adequate communication with fire, police and other officials.
- Prompt and effective response to emergencies, including:
 - gas detected inside or near a building,
 - fire located near or directly involving a pipeline facility,
 - explosion occurring near or directly involving a pipeline facility, and
 - natural disaster.
- Availability of personnel, equipment, tools, and materials as needed at the scene of the accident.
- Actions directed toward protecting first people and then property.
- Emergency shutdown and pressure reduction in pipeline system necessary to minimize hazards to life or property.
- Making safe any actual or potential hazard to life or property.
- Notification of fire, police, and other public officials of gas pipeline emergencies and the coordination with them of planned and actual responses during an emergency.

- Safe restoration of any service outage.
- Commencement of procedures for analyzing accidents and failures as soon after end of emergency as possible.

Each operator shall also be responsible for the proper action of his personnel with regard to emergency situations. The operator shall furnish supervisors responsible for emergency action with established emergency procedures, train operating personnel in emergency procedures, and review employee activities to determine whether procedures were effectively followed in an emergency.

Concerning the community, the operator must establish and maintain liaison with appropriate fire, police, and other public officials. The operator shall: learn the resources of government that can respond to a gas pipeline emergency, acquaint public officials with the operator's ability to act in an emergency, identify the types of emergencies for officials, and plan mutual assistance to minimize hazards to life or property.

Finally each operator shall establish a continuing educational program to enable customers, the public, appropriate government organizations and persons engaged in excavation-related activities to recognize a gas pipeline emergency for the purpose of reporting it. The program and media used must be comprehensive enough to reach all areas in which the operator transports gas.

4.4.3 State Program -- Texas Waste Discharge Program

In Texas, discharges of all "defined wastes," including industrial wastes, into or adjacent to the waters in the state are prohibited, except as authorized by a waste discharge permit, rule or other order of the Texas Department of Water Resources (TDWR) [TEX. WATER CODE ANN. §26.001 et seq. (Supp. 1980)]. The statutory definition of "waters in the state" includes ground water, percolating or otherwise, and all bodies of surface water, natural or artificial.

Although the Texas Water Development Board--the legislative branch of the Department--is statutorily required to set water quality standards by rule for all water in the state, most standards remain unwritten.

In practice, however, Permits Division of TDWR which negotiates the draft permit with the applicant before submission to the Texas Water Commission for approval and issuance usually applies EPA effluent limitations guidelines and NSPS for various point source categories. In addition, Permits Division assesses the effect of the proposed discharge on the water quality segment in which it is located. Water quality-related limits may dictate the application of effluent limitations more stringent than those required by EPA.

Although Texas does not yet have an approved NPDES delegation, close coordination exists between TDWR and EPA in administering their respective waste discharge permitting processes. For a new source, TDWR requires a "new source determination" from EPA prior to approval of a TDWR waste discharge permit. After approval of a waste discharge permit, TDWR

forwards a copy of the permit to EPA, which usually issues an identical NPDES permit to the applicant.

Texas also requires that all plans and specifications for disposal systems be reviewed and approved by the Executive Director of TDWR without notice and hearing.

Because of the potential for duplicative regulation of discharges resulting from surface mining operations at the state level, the TDWR entered into a Memorandum of Understanding (MOU) with the Texas Railroad Commission (TRC) in October, 1979, to expedite coordination of water quality-related regulation of surface mining. The MOU, which will not become effective until the Texas Water Development Board implements its provisions by rule, provides for the following:

- TDWR will promulgate a statewide rule applicable to all surface coal mining operations and consistent with NPDES guidelines and standards;
- TDWR will review all TRC surface mining applications to determine whether the TDWR general rule will adequately protect water in the state, whether an individual waste discharge permit will be required or whether water quality-related conditions will be recommended to the TRC for inclusion in the surface mining permit;
- Notices of applications for TRC mining permits must include all provisions and must be mailed and served in accordance with the Texas Water Code and TDWR regulations.

Until the MOU becomes effective, all waste discharges into state surface waters by lignite mines and gasification/ industrial facilities will require a separate waste discharge permit from TDWR. After the MOU is effective, waste discharges from lignite mines may be authorized simply by a surface mining permit from the TRC if the permit discharge conditions conform to the TDWR general rule. Waste discharges from gasification/ industrial facilities will, however, still require separate discharge permits from TDWR.

Footnotes - Section 4.4

¹Conventional pollutants are suspended solids (SS or TSS), biochemical oxygen demand (BOD or BOD₅), pH, and fecal coliform (intestinal bacillus bacteria which are nonpathogenic, but indicate sewage pollution). Toxic pollutants are those listed in the Consent Decree settling NRDC v. Train and nonconventional pollutants are any not included in the above two categories.

4.5 Water Use Controls

4.5.1 Introduction

This section catalogs a number of federal and state programs with disparate objectives under the general category of "water use authorizations." Water use controls include authorizations necessary for dam and levee construction, dredging and filling operations, and beneficial use of state water for mining and industrial purposes.

The regulatory programs and their applicability to the DF and MBG scenarios which are discussed in this section include the following:

- Corps of Engineers permits/approvals under Section 404 of the Clean Water Act and Sections 9, 10, and 13 of the River and Harbors Act of 1899;
- Department of Energy/U.S. Water Resources Council water resources availability review under the Federal Nonnuclear Energy Research and Development Act of 1974 (FNERDA);
- Texas Department of Water Resources (TDWR) water use permit;
- TDWR floodplain reclamation approval; and
- Texas Parks and Wildlife Department (TPWD) dredge and fill permit.

4.5.2 Federal Programs

4.5.2.1 Corps of Engineers Authorizations

Introduction

The Corps of Engineers derives its permitting authority from Sections 9, 10, and 13 of the River and Harbors Act of 1899 (Refuse Act)¹ and Section 404 of the Clean Water Act.² Section 9 of the Refuse Act prohibits the construction of any bridge, dam, dike or causeway over or across any waters of the United States unless authorized pursuant to state law and unless the plans are approved by the Corps.³ Section 10 of the Refuse Act prohibits the unauthorized obstruction or alteration of any navigable water of the United States unless authorized by permit or letter of permission from the Corps.⁴ Section 13 of the Refuse Act provides that the Corps may permit the discharge of refuse into navigable waters if the Corps determines that anchorage and navigation will not be injured.⁵ Finally, Section 404 of the Clean Water Act authorizes the Corps to issue permits, after notice and opportunity for public hearings, for the discharge of dredged or fill material into the waters of the United States at specified disposal sites.⁶

The term "navigable water of the United States" has been broadly construed by the Corps regulations to include the following: "coastal waters, wetlands, mudflats, swamps and similar areas; freshwater lakes, rivers, and streams that are used, were used in the past or are susceptible to transport interstate commerce; and freshwater wetlands, including marshes, shallows, swamps, and similar areas that are contiguous to the above . . . and that are periodically inundated and normally characterized by the prevalence of vegetation that requires

saturated soil conditions for growth and reproduction."⁷ A water-course that is considered "navigable" under state law will almost certainly be considered "navigable" under federal law. By Texas statute, for example, a stream which averages 30 feet wide from cut-bank to cut-bank from its mouth up to the disputed area is a "navigable" stream.⁸ The beds of all statutorily navigable streams belong to the State of Texas.

"Dredge material" and "fill material" are also broadly construed to include dams, dikes, levees, impoundments, causeways, and roadways; the building of any structure requiring rock, sand, or other pollutants for its construction; property protection and/or reclamation devices such as riprap, groins, and breakwaters.⁹

Criteria

The considerations involved in the Section 404 and Refuse Act decision-making processes are potentially very broad. Corps permit decisions are subject to NEPA requirements, to Executive Order No. 11988 requiring floodplain review and mitigation, and to Executive Order No. 11990 requiring wetlands review and mitigation. Among the policy issues which may be considered in the Corps permitting processes are the following:

- Is the proposed project in the public interest considering relevant factors such as conservation, economics, aesthetics, general environmental concerns, historic values, fish and wildlife values, flood damage prevention, land use, navigation, recreation, water supply, water quality, energy needs, safety, food production, and general welfare of people?

- Are there significant wetlands in the project?
- Do the benefits of the proposed alteration of the wetlands outweigh the damage to the wetlands resource?
- Is the proposed alteration of the wetlands necessary to realize those benefits?
- Is the proposed activity dependent on being located in, or in close proximity to, the aquatic environment?
- Are feasible alternative sites available?
- Can the applicant modify his proposal to eliminate or mitigate damage to fish and wildlife resources?
- Do the applicant's activities affect the quality of the waters of the United States?
- Do the activities which affect the quality of water of the United States comply with applicable state and federal effluent limitations, water quality standards, and management practices?
- Are there recognized historic, cultural, scenic, conservation, or recreational resources present in the project area?

- Can the proposed activity be conducted so as to be consistent with or avoid adverse effects on recognized historic, cultural, scenic, conservation, recreational, and similar values?
- Will the authorization of the works or structures result in interference with adjacent properties or federal water resource projects?
- Have any required federal, state, or local authorizations required for the project been previously denied?
- Can the impoundment structure be operated and maintained to ensure public safety?
- Are there alternatives available to proposed site or activity to avoid adverse effects from and incompatible development in floodplains?

Permit Process

The Clean Water Act Section 404 permit process triggers the application of NEPA requirements and may therefore require the preparation of an EID, EA, and EIS. Even if a finding of "no significant impact" is made, the Corp processes require: application; an opportunity for public notice, comment and hearing; and an opportunity for comment by other federal and state regulatory agencies. The 404 procedure is, therefore, potentially a lengthy two-year process involving extensive public and bureaucratic inputs on broad environmental policy issues.

Applicability

Various aspects of the surface mining process may require a permit from the Corps of Engineers: the construction of dams, dikes, levees, and impoundments on navigable watercourses within the mine site; the construction of levees and off-channel sedimentation ponds in wetlands; the discharge of sediment-bearing runoff from disturbed overburden into a navigable stream; the alteration of a navigable watercourse affecting its course, location, condition or capacity; and any mining activities which may obstruct navigation.

In addition, the construction of a major industrial or gasification facility may also require a permit from the Corps, if it will be constructed on, along, or near a navigable watercourse or if it will require the construction of a reservoir to provide process or cooling water.

4.5.2.2 FNERDA Water Resources Availability Review

The Federal Nonnuclear Energy Research and Development Act of 1974 provides that the Administrator of the Energy Research and Development Administration, the predecessor of the Secretary of Energy, shall formulate and carry out a comprehensive federal nonnuclear energy research, development, and demonstration (RD&D) program for specific alternative energy technologies.

Section 5912(a) of FNERDA requires the U.S. Water Resources Council to undertake assessments of water resource requirements and water supply availability for any nonnuclear energy technology (or combination of technologies) which are the subject of DOE's RD&D efforts and the commercial development of which could have significant impacts on water. This mandate

is being accomplished at the basin or zone level by the U.S. Water Resources Council through preparation of reports on general water availability for emerging energy technologies, usually in conjunction with the state water agencies or boards with jurisdiction over state surface and ground waters.

In addition, Section 5912(b) requires the Secretary of DOE, as a precondition to federal assistance, to request the U.S. Water Resources Council to prepare an individual assessment of water requirements and availability for any proposed demonstration project which may involve a significant impact on water resources. For any proposed federal assistance for commercial application of emerging energy technologies, Section 5912(c) provides, as a precondition to federal assistance, that the Water Resources Council provide to DOE an assessment of the availability of adequate water resources for such commercial application and an evaluation of the environmental, social, and economic impacts of the dedication of water to such uses. The assessment reports must be published in the Federal Register for public review 30 and 90 days, respectively, before expenditure of federal funds on the proposed project.

If the hypothetical medium Btu gasification facility in the MBG scenario were to require DOE funding under FNERDA for demonstration or commercial application, a FNERDA water resources availability review would be required. The review could potentially be a "show stopper" if insufficient surface or ground water supplies are not available.

4.5.3 State Programs

Under Texas law, separate permits or approvals will be required for the following activities:

- Impoundment and/or use of State water for beneficial purposes;
- Construction of a dam;
- Construction of a levee or other such improvement on, along, or near any stream that is subject to flooding so as to control, regulate, or otherwise change the floodwater of the stream; and
- Dredging or disturbing the banks or channel of a statutorily navigable stream.

4.5.3.1 TDWR Water Use Permit

Introduction

Under the Texas Water Code, uses of "State water" for other than domestic and livestock purposes must be authorized either by a permit issued by the Texas Water Commission, by a certified filing made with the Texas Board of Water Engineers in 1913-1914, or by a riparian claim filed with the Commission on or before September 1, 1969. "State water" includes all surface waters of every natural watercourse, lake, bay, or arm of the Gulf of Mexico.¹⁰ Among surface water right holders--permittees, certified filing holders, claimants--the use of State water is governed by a priority system, with water rights

being fully satisfied during a period of low streamflows in order of filing with the Commission.

Permit Process/Criteria

Water quality and water use permitting within the TDWR and before the Texas Water Commission (TWC) are presently discrete functions. The water use permit process requires application, public notice and hearing, and approval by the TWC--the judicial branch of TDWR--before permit issuance.

The criteria for permit issuance are as follows:

- Is unappropriated water--water which has not been used under existing water rights--available in the source of supply for the new use?
- Does the proposed use contemplate the application of water to a beneficial use?
- Does the new use impair existing water rights or vested riparian rights?
- Will the new use be detrimental to the public welfare?¹¹

Applicability

On-channel sedimentation ponds and rechannelization or diversion of streams for surface mining purposes will be beneficial uses of state water requiring a water use permit from TDWR/TWC. On-channel reservoirs or direct diversions of surface water for

industrial purposes (process water, cooling) in a gasification or industrial facility will also require water use permits. Depending upon the location of the facility, limited water availability in the Texas river basins south and west of the Brazos River Basin may present substantial barriers to construction of gasification or lignite-fired industrial facilities.

Excluded from requiring a water use permit under Texas law would be all uses of ground water (except underflow of a watercourse) and all off-channel impoundments impounding only ground water and/or diffused surface water which has never entered a watercourse.

4.5.3.2 TDWR Dam Construction Approval

The Texas Water Commission passes on the hydraulic and structural integrity of on-channel dams at two points: once during the permitting process when preliminary engineering plans are submitted and once following issuance of a permit when final engineering plans are approved.

During the initial permitting process, the Hydrology Unit of the TDWR usually performs a spillway adequacy analysis to determine the hydraulic adequacy of an existing or proposed dam to pass an acceptable test flood hydrograph. An application for a proposed structure is not usually sent to the Commission until the applicant has presented plans which are hydraulically acceptable to the Hydrology Unit.

Following the issuance of a permit, the Commission approves by order the final engineering plans to ensure that they are consistent with the preliminary plans and the permit as issued.

The engineering plans for any dam to be constructed in the course of surface mining activities or for provision of process or cooling water to a gasification or industrial facility must be approved by TDWR/TWC before construction commences.

4.5.3.3 TDWR Floodplain Reclamation Approval

The Texas Water Commission also approves by order preliminary plans to construct levees and "other such improvements" on, along, or near any stream which is subject to flooding "so as to control, regulate, or otherwise change the floodwater of the stream."¹² "Other such improvements" include construction of any structure (other than a dam authorized by a water use permit) and the placement of any fill or spoil material in the 100-year floodplain in a manner which significantly changes historical flooding patterns. The reclamation approval process requires application to TDWR and public notice and hearing prior to approval by the TWC.

The key issues in the approval process are the following:

- Is the proposed project safe and compatible with existing hydraulic conditions in the area?
- If a similar reclamation project is constructed on the other side of the stream, will the proposed project and the "mirror-image" project together raise the elevation of the 100-year floodplain by more than 12 inches?

After the Commission approves the preliminary plans for a reclamation project, the applicant must still obtain approval of the final plans from the Executive Director of the TDWR. This approval does not require notice and public hearing.

Any construction associated with a gasification or industrial facility or surface mining activity which will require work in the 100-year floodplain will require a reclamation approval by TDWR/TWC.

4.5.3.4 TPWD Dredge and Fill Permit

In addition to the authorization which must be obtained from the Texas Water Commission for dredging and filling under Section 16.238 of the Texas Water Code, a permit from the Texas Parks and Wildlife Department must be obtained for dredging the channel of or disturbing the banks of a statutorily navigable stream, the bed and banks of which belong to the State of Texas.

The key regulatory issues in the Parks and Wildlife permit process concern the impact of the dredging on recreation and navigation and the commercial value, if any, of the material to be dredged.

Any construction associated with a gasification or industrial facility or surface mining activity which will require dredging of a navigable stream or otherwise disturbing its banks will require a TPWD permit.

4.5.3.5 Harris-Galveston Coastal Subsidence District Permit

An industrial facility locating within the Harris-Galveston Coastal Subsidence District will require a permit from the District for any ground water well with a casing diameter of greater than 5 inches or if more than one well of any size is to be drilled. Permittees pay an application fee and a permit fee per 1000 gallons pumped. Prior to issuance of a permit, a public hearing must be held.

The District's purpose is to end subsidence, and its regulatory approach has been to control the amount of ground water withdrawal. In reviewing applications, the District's Board of Directors (15 members) considers the following:

- The purpose of the Act;
- The District's plan to end subsidence, adopted July 14, 1976;
- Quantity, quality, and availability of surface water at prices competitive with ground water;
- Economic impact of the applicant; and
- Relative effect on subsidence.

A permit is usually issued if no available source of surface water is found or if it is shown there would be a taking of private property without due process of law.

The District Plan, adopted in 1976, defines an "Area of Concentrated Emphasis" (ACE) consisting of all of Galveston

County and southeastern Harris County. The area was selected based on the following:

- General elevation $\leq 25'$ above msl;
- Critical subsidence problem in the area; and
- Availability of surface water as an alternative (from the Brazos, Trinity, and San Jacinto Rivers).

If it appears that surface water might be obtained by a well owner within a reasonable time and at reasonable cost, special conditions are appended to a permit requiring the permittee to study and report to the District the feasibility of securing surface water. Future regulatory action regarding subsequent permit applications will take the report into account.

The District continues to monitor rates of subsidence at eight dispersed locations. Ground water use is regulated on a geographical basis with a management strategy directed toward maximum ground water pumpage without subsidence.

With respect to the water utilized by the DF facility, the lignite-fired project may be refused a permit for ground water if competitively-priced surface water is available. Otherwise, it will probably receive a permit. Geographical location will be a factor in the decision.

Footnotes - Section 4.5

¹ 33 U.S.C. §401 et seq.

² 33 U.S.C. §1344.

³ 33 U.S.C. §401.

⁴ Id. §403.

⁵ Id. §407.

⁶ 33 U.S.C. §1344.

⁷ 33 Fed. Reg. 37124 (1977).

⁸ V.T.C.A. Nat. Res. Code 21.001(3).

⁹ Supra. note 7.

¹⁰ Tex. Water Code Ann. §11.021 (Supp. 1980).

¹¹ Id. §11.135(b).

¹² Id. §16.238.

4.6- Air Quality Controls

4.6.1 Introduction

The purpose of the Clean Air Act, as amended, is to protect and enhance air quality in order to protect public health and welfare.¹ The cornerstone of the Clean Air Act Amendments of 1970 was the provision for uniform national ambient air quality standards (NAAQS). There are two types of NAAQS:

- Primary standards for the protection of public health, including an adequate margin of safety; and
- Secondary standards for the protection of public welfare from known or anticipated adverse effects.²

NAAQS establish ceilings for pollutant concentrations and, therefore, determine the degree of control required of existing sources and the amount of development which can be added in any particular area. Because any area will have air quality either better or worse than the NAAQS, the NAAQS determine whether sources will be subject to prevention of significant deterioration (PSD) or the nonattainment area provisions of the Clean Air Act. EPA has published charts indicating the attainment status designations for all areas of the country.³

Based on air quality criteria established pursuant to Section 108 of the Act, EPA has set standards for seven pollutants: particulate matter, sulfur dioxide, oxides of nitrogen, non-methane hydrocarbons, carbon monoxide, photochemical oxidants, and lead. On February 9, 1979, EPA changed the photochemical oxidants NAAQS to an ozone standard and increased the allowed level by 50 percent.

Responsibility for limiting emissions to NAAQS by the statutory deadline lies primarily with the states by means of State Implementation Plans (SIP).⁴ Each state is required to develop a comprehensive program for meeting the NAAQS in the air quality control regions (AQCR) within its borders, subject to the review and approval of EPA. The EPA Administrator is authorized to substitute a plan to replace all or part of an inadequate SIP. Although NAAQS are not directly enforceable, the emission limitations and other requirements of SIP's may be directly enforced by EPA or the states or by citizens. Further, Section 118 of the Act authorizes states to establish even more stringent emission limitations than those necessary to attain or maintain NAAQS under Section 110.⁵

The original statutory deadline for attaining NAAQS was July 31, 1975, with the provision made for extension to July 31, 1977. In the Clean Air Act Amendments of 1977, Congress required that all SIP's be reviewed for adequacy and that plan revisions, where necessary to meet NAAQS, were to be submitted by January 1, 1979. Revised SIP's must provide for attainment of primary NAAQS as expeditiously as practicable, but no later than December 31, 1982. The date for attainment of photochemical oxidants and carbon monoxide NAAQS may, under certain conditions, be as late as December 31, 1987.

In addition to NAAQS, the Clean Air Act, as amended, established certain categories of national emission standards -- New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS). The Clean Air Act, as amended, also dictated which technology-based standards would be applied by the states on a case-by-case basis in PSD and nonattainment areas -- "best available control technology" in PSD areas and "lowest achievable emission rate" (LAER) for nonattainment areas. Table 4.6-1 defines these emission standards and shows their respective applicability.

TABLE 4.6-1. EMISSION STANDARDS UNDER THE CLEAN AIR ACT, AS AMENDED

Emission Standard	Standard of Performance	Additional Criteria*	Applicability
New Source Performance Standards (NSPS)	"Best technological system of continuous emission control adequately demonstrated."	• Cost of achieving emission reduction, • Non-air quality health and environmental impacts, and • Energy impact.	Generally applicable to all new sources: represents a ceiling for new sources.
National Emission Standards for Hazardous Air Pollutants (NESHAPS)	Under the Act, protection of public health with an adequate margin of safety from pollutants presenting a serious health hazard: i.e., zero level of emissions. Under EPA's proposed regs concerning suspected airborne carcinogens, "best available technology" will usually be minimum level of control.	None under Act, but under EPA's proposed regs, EPA will also consider • Economic impacts of various levels of control, • Energy impacts, and • Non-air environmental impacts.	Generally applicable to all emissions of asbestos, beryllium, mercury, and vinyl chloride. Others under consideration.
Best Available Control Technology (BACT)	"Best available control technology"	• Economic impacts, • Energy impacts, • Non-air environmental impacts, and • Other costs.	Applicable to new or modified sources by the states on a case-by-case basis in PSD areas. May be more stringent than NSPS.

*Additional criteria to be considered by EPA in formulating standard for a category of sources.

(Continued)

TABLE 4.6-1. Continued

Emission Standard	Standard of Performance	Additional Criteria*	Applicability
Lowest Achievable Emission Rate (LAER)	The more stringent of the following: • The most stringent limitation contained in any SIP for such class or category of sources, unless owner/operator demonstrates that such standards are not achievable; or • The most stringent limitation which is achieved in practice by such class or category of source.	Owner/operator may prove that LAER not economically or technically achievable, unless limitation is based on actual demonstration by member of class or category.	Applicable to new or modified sources by the states on a case-by-case basis in nonattainment areas. May be more stringent than NSPS or BACT.

*Additional criteria to be considered by EPA in formulating standard for a category of sources.

Section 4.6.2 describes the PSD permit program for areas cleaner than the NAAQS, and Section 4.6.3 describes the emission offset permit program for nonattainment areas. Section 4.6.4 describes the Texas air quality control program and its relationship to the federal program. Section 4.6.5 discusses the applicability of both federal and state programs to the MBG and DF scenarios.

4.6.2 Prevention of Significant Deterioration (PSD)

4.6.2.1 History

In 1972, the Sierra Club filed suit to enjoin EPA from approving certain portions of SIPs on the grounds that the SIPs failed to protect existing clean air areas against significant deterioration.⁷ EPA had taken the position that it lacked power to prohibit deterioration of clear air and that it must approve an SIP which was adequate to prevent ambient pollution levels from exceeding the secondary NAAQS. The court ruled, however, that the purposes and the legislative history of the Clean Air Act indicated Congressional intent to prevent significant deterioration of existing clean air regions and enjoined EPA from approving SIPs which did not provide for PSD.⁸ EPA's first generation PSD regulations were issued on December 5, 1974, and became effective January 6, 1975.⁹

In the Clean Air Act Amendments of 1977, Congress affirmed the PSD concept and set out detailed requirements for sources locating in such areas. Congress also directed the states to incorporate PSD provisions into the SIPs, but included no specific deadline for program implementation. EPA published revised PSD regulations on June 19, 1978. The proposed regulations were challenged by numerous industry and environmental groups and were subsequently remanded to EPA for substantial revision by the court in Alabama Power Company v. Costle.¹⁰ Based on the court's summary opinion, EPA published proposed rules on September 5, 1979.¹¹ Using an uncommon procedure, the Appeals Court then issued a final opinion on December 14, 1979,¹² which was written after review of the EPA's proposed PSD regulations of September 5. EPA subsequently published final PSD regulations on August 7, 1980.¹³

4.6.2.2 Area Classifications

States can identify in their SIP's the local land use goals for each clean area through a system of area classifications. There are three types of area classifications. Class I areas allow only a small degree of air quality deterioration, while Class II areas can accommodate normal well-managed industrial growth. Class III areas allow major development. Except for certain wilderness areas and national parks, all clean areas of the country were initially designated Class II.

"Significant deterioration" is said to occur when the amount of new pollution generated by a new or modified source exceeds the applicable allowable increase ("increment"), the amount of which varies with the area classification. In Class I areas, allowable PSD increments are set at approximately two percent of the NAAQS for the corresponding averaging period. In Class II and III areas, increments of 25 percent and 50 percent of NAAQS, respectively, allow moderate to high industrial growth.

The reference point for determining air quality deterioration is the baseline concentration, which is essentially ambient concentration existing at the time of the first PSD permit application submittal affecting the area. To date, only PSD increments for sulfur dioxide (SO₂) and total suspended particulates (TSP) have been established, but EPA is currently investigating appropriate increments or alternatives to increments for the other criteria pollutants. Table 4.6-2 presents the PSD increments for SO₂ and TSP for the three designated PSD classes. For comparison, it also presents corresponding NAAQS for SO₂ and TSP and for the other criteria pollutants.

TABLE 4.6-2. AMBIENT STANDARDS AND MAXIMUM
ALLOWABLE PSD INCREMENTS

Pollutant	NAAQS ($\mu\text{g}/\text{m}^3$)			Maximum PSD Increments ($\mu\text{g}/\text{m}^3$)		
	Primary Standard	Secondary Standard	Average Time	Class I	Class II	Class III
SO ₂	80	60	Annual(b)	2	20	40
	365	260	24-hour(c)	5	91	182
		1,300	3-hour(c)	25	512	700
TSP	75	60	Annual(b)	5	19	37
	260	150	24-hour(c)	10	37	75
Ozone	325	235	1-hour(c)	--	--	--
NO ₂	100	100	Annual(b)	--	--	--
Pb	1.5	1.5	3-month(b)	--	--	--
CO	10,000	10,000	8-hour(c)	--	--	--
	40,000	40,000	1-hour(c)	--	--	--

(a) These increments shall always be such that NAAQS are not violated.

(b) Never to be exceeded.

(c) Not to be exceeded more than once per year.

The principal mechanism within the SIP to implement the objectives of the PSD program is the preconstruction review process which requires that new major stationary sources and major modifications are reviewed prior to construction to ensure compliance with NAAQS, applicable PSD increments, and BACT requirements.

4.6.2.3 Source Applicability

Because of the time and expense of the PSD permitting process, avoidance of PSD review has become a major element in many companies' plans for new or modified facilities. Because full-scale PSD monitoring and review takes over a year, questions of applicability are more important with respect to PSD than to most other areas of environmental permitting. In general, the following factors determine the applicability of PSD requirements.

- Size of the emitting source;
- Potential and actual emissions;
- Amount of emissions increases or decreases at the source in the past five years; and
- Location.

Only "major stationary sources" are subject to PSD regulations. Source size is defined in terms of "potential to emit." "Potential to emit" means the capability at maximum design capacity to emit a pollutant after the application of all required air pollution control equipment and after taking into account all federally enforceable requirements restricting the type or amount of source operation. A "major stationary source" is any source type belonging to a list of 28 source categories which emits or has the potential to emit 100 tons per year or more of any pollutant subject to regulation, or any other source type which emits or has the potential to emit such pollutants in amounts equal to or greater than 250 tons per year. Table 4.6-3 presents a list of the 28 major source types subject to PSD review if their potential emissions exceed 100 tons per year.

EPA defines "sources" differently for PSD purposes than for source review in nonattainment areas. The term "stationary source" means any building, structure, facility, or installation which emits any air pollutant. The terms "building, structure, facility, or installation" are defined broadly in the regulations to include all emission points within what is generally considered an industrial plant. All emission points or activities which are part of the same "major group" under the Standard Industrial Classification code will be treated as part of the same source for PSD purposes: in general, activities which belong to the same industrial grouping, are located on contiguous or adjacent properties, and are under common control.

A "major modification" is generally a physical change in or a change in the method of operation of a major stationary source which would result in a significant net emissions increase in the emissions of any regulated pollutant. In order to determine if there will be a net emissions increase, the owner/operator must do the following calculations:

TABLE 4.6-3. MAJOR SOURCE TYPES IN PSD REGULATION*

-
1. Fossil Fuel-Fired Steam Electric Plants of More Than 250 Million.
 2. Coal Cleaning Plants (with Thermal Units).
 3. Kraft Pulp Mills.
 4. Portland Cement Plants.
 5. Primary Zinc Smelters.
 6. Iron and Steel Mill Plants.
 7. Primary Aluminum Ore Reduction Plants.
 8. Primary Copper Smelter.
 9. Municipal Incinerators Capable of Charging More Than 250 Tons of Refuse Per Day.
 10. Hydrofluoric Acid Plants.
 11. Sulfuric Acid Plants.
 12. Nitric Acid Plants.
 13. Petroleum Refineries.
 14. Lime Plants.
 15. Phosphate Rock Processing Plants.
 16. Coke Oven Batteries.
 17. Sulfur Recovery Plants.
 18. Carbon Black Plants (Furnace Process).
 19. Primary Lead Smelters.
 20. Fuel Conversion Plants.
 21. Sintering Plants.
 22. Secondary Metal Production Plants.
 23. Chemical Process Plants.
 24. Fossil Fuel Boilers (or Combination Thereof) Totaling More Than 250 Million British Thermal Units Per Hour Heat Input.
 25. Petroleum Storage and Transfer Units with a Total Storage Capacity Exceeding 300,000 Barrels.
 26. Taconite Ore Processing Plants.
 27. Glass Fiber Processing Plants.
 28. Charcoal Production Plants.
-

*Sources in this list must obtain a PSD permit if their potential emissions exceed 100 tons per year; all other sources must obtain a PSD permit if their potential emissions exceed 250 tons per year.

- Quantify the amount of the proposed emissions increase;
- Document and quantify all emissions increases and decreases that have occurred or will occur contemporaneously (within the past five years) and have not been evaluated as part of a PSD review; and
- Total the proposed emissions changes and the unreviewed contemporaneous changes.

If the resultant net emissions increase is larger than certain values specified in the regulations, the modification is major and subject to PSD review. Certain specified changes are exempted from the definition of major modification.

If a source or modification qualifies as major, its prospective location or existing location must also qualify as a PSD area in order for PSD review to apply. A PSD area is one formally designated as "attainment" or "unclassifiable" for any pollutant for which an NAAQS has been established. Major new or modified sources located in such an area will be subject to PSD review for all pollutants, except those (1) emitted in "major" amounts, and (2) for which the plant's location is designated as nonattainment. So long as the source is "major" for at least one pollutant and is located in an area designated attainment for any criteria pollutant, PSD review will extend to both attainment and nonattainment pollutants.

Fugitive dust emissions are defined as "particles of native soil which are uncontaminated by pollutants resulting from industrial activity." EPA has promulgated a list of 27

source categories, specified in Table 4.6-4, for which fugitive emissions must be included in the calculation of potential emissions.

4.6.2.4 Permit Process

All sources meeting the PSD source applicability requirements must do the following in order to obtain a PSD permit for a major new or modified source:

- Must apply BACT;
- Must conduct an ambient air quality analysis based on ambient air quality monitoring and/or dispersion modeling;
- Must analyze impacts to soils, vegetation, and visibility, including impacts from general commercial, residential, industrial, and other growth associated with the proposed source or modification;
- Must not adversely impact a Class I area;
- Must solicit public participation and comment by providing public notices; and
- Must start construction within a reasonable time (18 months).

In a BACT analysis, the reviewing authority must evaluate the energy, environmental, economic and other costs associated with each alternative technology and the benefit of

TABLE 4.6-4. FACILITY CATEGORIES FOR WHICH FUGITIVE EMISSIONS
MUST BE CALCULATED IN POTENTIAL EMISSIONS

- 1) Coal cleaning plants (with thermal dryers);
 - 2) Kraft pulp mills;
 - 3) Portland cement plants;
 - 4) Primary zinc smelters;
 - 5) Iron and steel mills;
 - 6) Primary aluminum ore reduction plants;
 - 7) Primary copper smelters;
 - 8) Municipal incinerators capable of charging more than 250 tons of refuse per day;
 - 9) Hydrofluoric, sulfuric, or nitric acid plants;
 - 10) Petroleum refineries;
 - 11) Lime plants;
 - 12) Phosphate rock processing plants;
 - 13) Coke oven batteries;
 - 14) Sulfur recovery plants;
 - 15) Carbon black plants (furnace process);
 - 16) Primary lead smelters;
 - 17) Fuel conversion plants;
 - 18) Sintering plants;
 - 19) Secondary metal production plants;
 - 20) Chemical process plants;
 - 21) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;
 - 22) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;
 - 23) Taconite ore processing plants;
 - 24) Glass fiber processing plants;
 - 25) Charcoal production plants;
 - 26) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;
 - 27) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.
-

reduced emissions that the technology would bring. Table 4.6-5 specifies the basic elements of a BACT determination.

The ambient air quality analysis requirement has two purposes:

- To estimate increment consumption and demonstrate that PSD increments are not jeopardized; and
- To show that the NAAQS are met.

For pollutants for which an NAAQS exists, the applicant must provide ambient monitoring data that represents air quality levels in the year's period preceding the PSD application. This data may be obtained from a regulatory agency or a private source. If no such data exists, the applicant may have to conduct its own monitoring. For pollutants for which there is no NAAQS, the required analysis will usually be based on dispersion modeling.

4.6.3 Nonattainment --Emission Offset Interpretative Ruling

4.6.3.1 History

The Emission Offset Interpretative Ruling describes the requirements for preconstruction review which apply to large new or modified stationary sources in nonattainment areas. Originally promulgated by EPA on December 21, 1976, the rule was amended by EPA on January 16, 1979 as a result of public comment on the original rule and changes required by the Clean Air Act Amendments of 1977. The requirements in this ruling were to be incorporated by the states in their new source review

TABLE 4.6-5. BASIC REQUIREMENTS OF PSD BACT DETERMINATION

General Requirements	Energy Impact Assessment	Environmental Impact Assessment	Economic Impact Assessment
Describe proposed control system at each emission point.	ID amount, type, and source of energy required by each alternate (v. proposed BACT system).	ID beneficial and adverse air pollution, water pollution and solid waste impacts associated with each alternate (v. proposed BACT system).	Present separately the investment, operations limit production, maintenance and annualized cost for each alternate (v. proposed BACT system).
Discuss all viable, more efficient alternate systems.	ID type and amount of source fuels required to comply with each alternate's requirement (v. proposed BACT system).	Discuss any irreversible resource commitments associated with each alternate (v. proposed BACT system).	Assess local economic impacts associated with each alternate (v. proposed BACT system).
Justify inappropriateness of utilizing alternates.	Evaluate impact on locally available coal.	Assess any other environmental impacts.	
Present incremental analysis of energy, environmental and economic impacts of each alternate (v. proposed BACT system).	Assess energy production impacts of each alternate (v. proposed BACT system).		

permit process until July 1, 1979, or until such time as the states substitute an EPA-approved New Source Review (NSR) program compatible with Part D of the Clean Air Act. Because EPA has no authority under the Clean Air Act to issue construction permits for proposed sources in nonattainment areas, the review for such sources is to be performed by the states.

With respect to facilities locating in or impacting nonattainment areas, EPA's Emission Offset Interpretive Ruling terminated as of July 1, 1979 and has been replaced by state-adopted, EPA-approved New Source Review requirements. In the absence of an EPA-approved program, no permits to construct or modify new sources or facilities may be issued by the states. Many states, however, have elected to continue using the emission offset ruling on a case-by-case basis beyond July 1, 1979, in reviewing new sources impacting nonattainment areas. Other states have adopted in their revised SIP's even more stringent controls on existing sources than would be necessary to bring nonattainment areas into attainment, thereby incorporating a growth allowance in their SIP's and rendering an emission offset approach unnecessary.

In response to the Alabama Power Company decision, it is expected that EPA will make changes in a number of key definitions which will also affect the offset interpretive ruling. On May 13, 1980, EPA amended the Emission Offset Interpretive Ruling as follows:

- Made all sources located in a designated nonattainment area subject to the Emission Offset Interpretive Ruling even if they were to be located in a "clean pocket" within the nonattainment area; and

- Exempted all sources that were to be located in an attainment area from the Ruling even if a source had a "significant" impact on a nonattainment area and contributed significantly to any violations.¹⁴

Furthermore, EPA on May 22, 1980, proposed rules to protect visibility in mandatory Class I areas which would require all new or modified sources to be reviewed with respect to their impact on visibility in the mandatory Class I areas.

4.6.3.2 Source Applicability

Part D of the Clean Air Act Amendments of 1977 requires that all major stationary sources having potential emissions (uncontrolled emissions at design capacity) of 100 tons or more per year be reviewed under the Emission Offset Interpretive Ruling (EOIR).

The original EPA EOIR applied to both sources located in nonattainment areas and to sources in attainment areas which exceeded "significant concentration increments" in nonattainment areas. The present EOIR, as amended on May 13, 1980, applies only to proposed new or modified sources with potential emissions exceeding 100 tons per year located within a designated nonattainment area.

In contrast with the PSD regulations, the EOIR does not allow exemptions from the EOIR for offsetting emissions within a plant. Regardless of how many intrasource or intraplant offsets an applicant may be able to find, the EOIR's requirements must still be met if the proposed modification or new source exceeds 100 tons per year of potential emissions.

4.6.3.3 Permit Process

For each proposed new source or modification with allowable emissions exceeding 50 tons per year, 1000 pounds per day, or 100 pounds per hour located (or locating) in a non-attainment area, the owner/operator of a new or modified source must meet the following conditions for a permit:

- Must meet an emission limitation corresponding to the "lowest achievable emission rate" (LAER);
- Must be in compliance with all applicable emission limitations and standards or on enforceable compliance schedules with respect to all existing major sources in the same state;
- Must provide intrapollutant emission reductions (offsets) from existing sources in the area of the proposed source (whether or not under the same ownership) on a greater than one-for-one basis; and
- Must provide a positive net air quality benefit in the affected area, (usually) as demonstrated by dispersion modeling.

LAER is statutorily defined for new sources as the more stringent of the following:

- The most stringent limitation contained in any SIP, unless the owner/operator demonstrates that the limitations are not achievable; or

- The most stringent limitation achieved in practice.¹⁵

LAER may be more stringent than NSPS and BACT.

For new sources obtaining permits by applying offsets after January 16, 1979, the state reviewing authority may allow offsets that exceed the greater than one-for-one requirement to be "banked"; saved to provide offsets for a source seeking a future permit. Similarly, the reviewing authority may allow the owner of an existing source who reduces emissions beyond that required in the SIP to "bank" the resulting reduction for future use with a new source permit.

The procedural requirements for an emission offset permit are defined by the state New Source Review Program, rather than by federal regulations.

4.6.4 Texas Air Control Board Permits

4.6.4.1 Background

The Texas Clean Air Act, administered by the Texas Air Control Board (TACB), requires the dual permitting of air contaminant sources in Texas. Section 3.27 of the Act provides that any person who plans to construct a new facility or to modify an existing facility which may emit air contaminants to apply for and obtain a construction permit from TACB before commencing work on the facility. If a permit to construct is issued, Section 3.28 of the Act requires the owner/operator to apply for a permit to operate within 60 days after the facility has begun operation.

The principal regulatory issues in both permit processes is whether the facility, as proposed and as constructed, will comply with applicable air control standards and the intent of the Texas Clean Air Act. The substantive requirements for permit approval are contained in a series of regulations adopted by TACB:

- Regulation I: Control of Air Pollution from Visible Emissions and Particulate Matter;
- Regulation II: Control of Air Pollution from Sulfur Compounds:
- Regulation III: Control of Air Pollution from Toxic Materials;
- Regulation IV: Control of Air Pollution from Motor Vehicles;
- Regulation VI: Control of Air Pollution by Permits for New Construction or Modification; and
- Regulation VII: Control of Air Pollution from Nitrogen Compounds.

Taken together, these regulations comprise the substantive elements of Texas' State Implementation Plan. Texas' SIP has been conditionally approved by EPA, subject to implementation of certain special programs such as inspection/maintenance (I/M) for automobiles in Harris County which is nonattainment for ozone. According to TACB, EPA's conditional approval authorizes TACB to issue construction and operating permits in nonattainment areas for so long as TACB adheres to a compliance schedule for

incorporating these special program in the Texas SIP. Implementation of the Harris County I/M program is so controversial, however, that TACB has abdicated the problem to the Texas Legislature for implementation. If the Legislature does not pass an implementation program, EPA could conceivably revoke its conditional approval of the Texas SIP. In that event, TACB would be unable to issue permits for new sources in nonattainment areas.

In addition, Texas has not yet received the PSD delegation of authority from EPA; that is, the authority to administer the PSD permit program, subject to EPA's final approval. Delegation is believed to be imminent, however; probably by February 1981, if EPA and TACB can reach a compromise with respect to certain modeling techniques. Until final approval of the Texas SIP and delegation of PSD authority, separate PSD permits will be required from EPA and TACB.

4.6.4.2 Permit Requirements/Process

The TACB construction and operating permit programs basically incorporate EPA's PSD and emission offset permit requirements, except that Texas' SIP has not yet been revised to incorporate EPA's May 17, 1980 PSD regulations as modified by the Alabama v. Costle decision.

A construction permit application is acted upon by TACB following public notice of intent to construct, and an opportunity for public comment prior to permit approval. Public hearing is discretionary with the Board.

Section 3.21 of the Texas Clean Air Act provides that TACB may grant individual variances from its regulations

"whenever it is found, upon presentation of adequate proof, that compliance with any provision of this Act, or any rule or regulation of the board will result in an arbitrary and unreasonable taking of property, or in the practical closing and elimination of any lawful business, occupation or activity, in either case without sufficient corresponding benefit or advantage to the people." Following a mandatory public hearing, the Board may approve a variance subject to a timetable for compliance with appropriate emission limitations. The U.S. Supreme Court has held, however, that state-approved variances cannot compromise a state's compliance with NAAQS by the statutory deadlines.

4.6.5 Applicability

Both the mine-mouth lignite gasification plant and the lignite-fired industrial facility postulated in the MBG and DF scenarios, respectively, will be subject to applicable PSD and emission offset permit requirements of EPA and TACB. Until TACB receives the PSD delegation from EPA, a new source will have to obtain a PSD permit from EPA and separate construction/operating permits from TACB.

Of greater significance, however, are the different impacts of fugitive dust emissions from the mines associated with each scenario. There are numerous sources of fugitive emissions from a surface mine: dust emanating from haul roads, drag line and bulldozer operations, explosions, and overburden piles. Surface mines are not presently among the sources listed by EPA for which fugitive emissions must be included in the calculation of potential emissions. Consequently, fugitive dust emissions from the mines only will not be counted in determining whether such mines are "major stationary sources" subject to PSD review.

Unless non-fugitive point sources within the mine site exceed 250 tons per year, the mine only will not require PSD review on the basis of fugitive emissions.

Fugitive emissions from a mine may be included in any air impact analyses of a mine-mouth lignite gasification plant, however, since fuel conversion plants are among the listed sources for which fugitive emissions must be included in the calculation of potential emissions. If the mine is contiguous to the gasification plant and if the mine and the plant are commonly controlled, the fugitive dust emissions from the mine may be viewed as secondary emissions associated with the mine-mouth plant. This could potentially create serious problems for the MBG scenario because fugitive emissions from the mine are likely to exceed available PSD increments. This regulatory problem would not, however, be present in the DF scenario.

Footnotes - Section 4.6

¹ 42 U.S.C. §7401 et seq.

² Id. §7409.

³ 44 Fed. Reg. 8202, et seq. (1979).

⁴ 42 U.S.C. §7410.

⁵ Id. §7418.

⁶ 44 Fed. Reg. 58642, et seq.

⁷ Sierra Club V. Ruckelshaus, 344 F. Supp. 253 (D.D.C. 1972) aff'd by an equally divided court sub nom. Fri V. Sierra Club, 412 U.S. 41 (1973).

⁸ Id.

⁹ 40 C.F.R. §52.21.

¹⁰ 606 F.2d 1068 (D.C. Cir. 1979).

¹¹ 44 Fed. Reg. 51924.

¹² Alabama Power Company V. Costle, supra; note 10.

¹³ 45 Fed. Reg. 52676.

¹⁴ 45 Fed. Reg. 31307.

¹⁵ 42 U.S.C. §7501.

4.7 Solid Waste Controls

4.7.1 Introduction

In September, 1976, Congress enacted amendments to the Solid Waste Disposal Act.¹ These amendments, the Resource Conservation and Recovery Act (RCRA)² and EPA regulations promulgated thereunder, attempt to impose a comprehensive, nationwide program for controlling solid wastes. One of the Congressional Committees responsible for drafting RCRA claimed that "the approach taken by this legislation eliminates the last remaining loophole in environmental law, that of unregulated land disposal of discarded materials and hazardous wastes...."³

The basic approach of RCRA is to divide the regulation of solid waste into two categories--hazardous wastes and other solid wastes.⁴ The main thrust of the Act is directed toward control of hazardous wastes. The centerpiece of EPA's program is the so-called "cradle-to-grave" feature. Essentially, this feature consists of a manifest system by which hazardous waste material can be tracked from its origin at the plant of a waste generator through the hands of each transporter, to its final disposal at an EPA-approved disposal site.

The "cradle-to-grave" system of manifests and permitting places accountability for the final disposal of hazardous wastes on the generator responsible for creating the waste. New facilities, such as those under consideration here, will not be able to hire independent contractors to haul wastes away in order to avoid continuing responsibility for the disposal problems these wastes pose.

Moreover, RCRA requirements eliminate the attractiveness of the formerly popular practice of storing hazardous wastes on-site. On-site hazardous waste storage in Texas, prior to RCRA, was a means of avoiding the necessity of permitting. On-site storage was explicitly exempted from permitting requirements under §F of the Texas Solid Waste Disposal Act: even after RCRA, on-site disposal of non-hazardous wastes without a permit is permissible.⁵ In Texas, as in other states, approximately 90 percent of all hazardous waste has traditionally been disposed of on-site.⁶ The majority of on-site disposal facilities in Texas will be unable to meet RCRA hazardous waste disposal standards. It has been observed that "[t]he siting of hazardous waste disposal facilities may prove to be one of the most insoluble environmental problems presented in planning the industrial plants of the future."⁷

At present, however, neither EPA nor the Texas Department of Water Resources which administers the Texas waste disposal program for industrial wastes considers the primary wastes from coal- or lignite-fired boilers to be hazardous. EPA promulgated criteria for designating hazardous wastes in the Federal Register on May 19, 1980, pursuant to §3001 of RCRA. At that time, "fly ash, bottom ash waste, slag waste, and flue gas emission control waste generated primarily from the combustion of coal" were designated as "solid wastes which are not hazardous wastes" [40 C.F.R. Part 261.4(b)(4)]. In an explanatory text accompanying the regulations, EPA indicated that this designation was made "because it appears likely that Congress will act before November 19, 1980, to exempt these wastes. . . . This exclusion will be revised, if necessary, to conform to the legislation which is ultimately enacted" [Federal Register, May 19, 1980, page 33089].

Congress acted in the Solid Waste Disposal Act Amendments of 1980 (PL 96-482). The Amendments were signed into law on October 21, 1980, and directed the Administrator of EPA, within two years, to do the following:

Conduct a detailed and comprehensive study and submit a report on the adverse effects on human health and the environment, if any, of the disposal and utilization of fly ash waste, bottom ash waste, slag waste, flue gas emission control waste, and other byproduct materials generated primarily from the combustion of coal or other fossil fuels.

Section 7(3)(A) of the Solid Waste Disposal Act Amendments of 1980 indicates that the above coal-fired wastes shall continue to be regulated as non-hazardous wastes for a period which ends six months after the date of submission of the Administrator's study. Thus, for roughly the next two and one half years, a regulatory moratorium is in place. If EPA finally resolves that coal-fired wastes are non-hazardous, then on-site disposal without a permit will be permissible.

Following recent EPA rulemaking,⁸ Texas, through the Texas Department of Water Resources, is modifying its solid waste management program to reflect federal requirements in order to obtain exclusive state administration of solid waste controls.⁹ Texas is seeking both interim and permanent authority to exclusively administer solid waste management programs in the state. Interim status has now been granted by EPA.

The interim state program is required to be substantially equivalent to the federal program administered by EPA. Given that requirement, and the fact that the Texas program is presently undergoing major changes to accommodate federal rules, the discussion below necessarily focuses upon federal requirements.

4.7.2 RCRA Requirements

4.7.2.1 Performance Standards

Hazardous waste management under RCRA includes four major elements:

- Federal identification of hazardous wastes;
- A manifest system for tracing hazardous wastes from generator, to transporter, to disposal facility (the "cradle-to-grave" program);
- Federal minimum standards for hazardous waste disposal, enforced through permits for disposal facilities; and
- State implementation of hazardous waste management programs at least equivalent to the federal program.

The "substantial equivalency" requirement for federal approval of state programs means that, as a practical matter, a state should merely adopt federal definitions and standards for hazardous waste controls. Texas has done precisely that, at least in the regulations it has proposed for EPA review.

The cradle-to-grave manifest system required by RCRA affects hazardous waste generators and transporters. Generators must keep records and report to EPA, or to authorized state officials, their activities involving hazardous waste management. Along with this notice component, generators must also initiate a shipping manifest system to keep track of wastes from the time of their production until their treatment, storage, or disposal in permitted facilities. Transporters must keep track of their activities, must accept only properly labeled and containerized wastes, and must comply with the manifest system. Most importantly, transporters must deliver hazardous wastes only to the permitted disposal facility which the generator has identified on the manifest. This insures accountability should irregularities come to light at any point in time.

Generators and transporters of hazardous wastes are not required to hold permits. Disposal, treatment, or storage of these wastes, either on-site (for more than 90 days) or off-site is, however, prohibited except in accordance with a permit. Owners and operators of storage, treatment, and disposal facilities will be required to at least meet forthcoming, stringent EPA performance standards. These standards will govern location, design, construction, operation, and maintenance of facilities. State standards must be at least as stringent as EPA standards.

States are authorized, even encouraged, to administer and enforce a hazardous waste regulatory program in lieu of EPA. The state program must be substantially equivalent to the federal program and not so inconsistent with programs in neighboring states as to inhibit the interstate movement of waste materials.

Federal guidelines are thresholds. That is, states may be more stringent if they wish so long as interstate consistency requirements are not violated. Presently, there is no indication that Texas' rules will depart in any significant way from federal standards. Once Texas satisfies federal authorities as to the adequacy of its program, it may, of course, introduce modifications to address problems peculiar to the state. Modifications will be subject to EPA review. Even where state programs have been approved and implemented, EPA retains, upon notice to the state, enforcement power against individual violators.

4.7.2.2 Permit Process

Any person who owns, operates, or proposes to own or operate a facility that treats, stores, or disposes of hazardous wastes must receive a permit from EPA or an authorized state. This includes on-site storage for more than 90 days. Application for a permit is made to either the Regional Administrator of EPA (Region VI office in Dallas for Texas applicants) or to the appropriate state agency. The basic RCRA application process is outlined in Table 4.7-1. In Texas, the administering agency is the Texas Department of Water Resources for industrial wastes.

Passage of RCRA coupled with emergency adoption of rules adding a new subchapter to Chapter 22 of the Texas Water Development Board rules in order to implement §4(f)(2) of the Texas Solid Waste Disposal Act, had the practical effect of broadening the state's permit requirements for hazardous waste management at least to the extent required by RCRA. Most importantly, the new Texas rules had the effect of requiring "on-site" hazardous waste management facilities to submit applications for hazardous waste permits. Then existing and all future on-site

TABLE 4.7-1. RCRA APPLICATION PROCESS

	Substantive Requirements	Compliance
Part A	Requires a description of the amounts and types of hazardous waste to be handled and the processes for handling them [§122.24].	File consolidated application forms 1 and 3 (Appendix C).
Part B	Requires detailed information pertinent to the facility's operation and physical characteristics.	Describe procedures, structures, and equipment to be used during both normal operations and in emergency situations. Submit chemical and physical analyses of the hazardous wastes to be handled.

facilities must hold a permit in order to legally continue operations.

4.7.3 Texas Solid Waste Disposal Program

When the Texas Solid Waste Disposal Act was passed in 1970, the Texas Water Quality Board was assigned jurisdiction for industrial solid waste with the duty "to safeguard the health, welfare and physical property of the people through controlling the collection, handling, storage and disposal of solid wastes." In 1973, the Water Quality Board published a plan for industrial solid waste management based on existing management practices and promulgated regulations establishing design criteria and permit requirements for commercial (off-site) disposal operations.

The Texas Department of Health (TDH) has jurisdiction over municipal solid waste management. Following the passage of RCRA by Congress in 1976, Texas took steps to gain delegation of the RCRA solid waste management program from EPA. On January 5, 1979, the Governor of Texas designated the entire State of Texas as a single region for industrial solid waste management. Concurrently, the Texas Department of Water Resources was designated as the agency responsible for developing the industrial solid waste management plan mandated by RCRA. Effective November 19, 1980, the Texas Water Development Board adopted rules for industrial solid waste management which include requirements for generators and transporters, owners, and operators of industrial solid waste management facilities.

As part of the delegation process, TDWR and TDH in early December, 1980, held a number of public hearings around the state on the proposed Solid Waste Management Plan for Texas, 1980-1986.

The regulations adopted by the Texas Water Development Board governing industrial solid waste generation, transport, and disposal generally track the RCRA program and include the following elements:

- Generators

All waste generators are required to:

- keep records of industrial solid waste storage processing, and disposal activities;
- retain such records for a minimum of three years; and
- submit an annual summary of activities.

A generator of hazardous industrial waste must:

- determine if his waste is hazardous by consulting the lists of hazardous waste contained in 40 CFR part 261 or, if the waste is not listed, by testing it, using procedures specified in the part 261 regulations, to establish if it is ignitable, corrosive, reactive or toxic;
- obtain an EPA identification number from the TDWR;
- obtain a facility storage permit if waste is accumulated on the generator's property more than 90 days;
- use appropriate containers and label them properly for shipment;
- issue a manifest to control transport of all Class I industrial waste;
- follow manifest procedures to assure that the waste arrives at the designated facility; and
- submit an annual summary of activities.

- Transporters

Transporters of hazardous and Class I industrial solid waste are required to:

- obtain an EPA identification number from the TDWR;
- comply with manifest system requirements;
- deliver the entire quantity of the waste to the facility designated on the manifest;
- retain a copy of the manifest for 3 years;
- comply with the U.S. Department of Transportation regulations and the Texas Oil and Hazardous Substances Spill Contingency Plan pertaining to reporting of spills or discharges; and
- clean up any waste discharged during transport.

- Facility Owners and Operators

Existing Department rules for owners and operators of industrial hazardous waste storage, processing and disposal facilities include:

- preparedness for and prevention of any occurrence which may endanger human health or the environment;
- contingency plans and emergency procedures;
- use of a shipping control ticket (manifest);
- record keeping and reporting procedures;
- ground water monitoring;
- closure and post-closure plans; and
- technical standards for containers, tanks, surface impoundments, waste piles, land treatment, landfills incinerators, thermal treatment and chemical physical and biological treatment.

4.7.4 Applicability

Both the MBG and DF scenarios require consideration of the problem of solid waste disposal. Wastes from mining activities are explicitly covered by major solid waste legislation at the federal and state levels. The principal solid waste by-product of mining is undifferentiated overburden which is returned to the mines. This material is, however, exempted from federal and state solid waste programs and is controlled under the surface mining acts of both levels of government. Thus, solid waste control from mining per se is not as important a consideration under this heading as it might first appear to be. Accordingly, discussion here will be confined to the more critical question of solid waste produced by facilities utilizing lignite.

Both a mine-mouth gasification facility and a direct-fired facility will create solid waste management problems from industrial processes and from air and water pollution control equipment. Even absent these other pollution controls and their solid waste components, any industrial facility processing or burning lignite will produce significant quantities of solid wastes. Many of these solid wastes will be classified as hazardous. In the industrial setting, it is these hazardous wastes which are of greatest concern to solid waste managers and the public. Accordingly, Congress and EPA have focused attention on this type of waste in establishing controls over solid wastes.

In the wake of EPA regulations promulgated under RCRA, there is a high degree of uncertainty regarding the management of hazardous solid waste in the immediate future. This uncertainty is heightened in the present context by language in

EPA regulations excluding from the definition of solid waste from combustion of coal. This means that the DF scenario involving a lignite-fired industrial boiler as the consumer would presently be exempt from RCRA permit requirements since non-hazardous wastes may be stored on-site without a permit.

Although the language of RCRA offers no explanation on this point, supplementary information supplied by EPA in the Federal Register of May 19, 1980 (at 33089), points out that bills to amend RCRA are pending before Congress. These bills, if passed, will preclude EPA's assertion of authority over certain utility and energy development wastes. Apparently, a separate program for managing these high volume, special category wastes is contemplated by Congress. This hiatus in federal regulatory authority is clearly temporary. It is likely that a waste management program substantially similar to RCRA will be established for this class of waste in the near future. Meanwhile, it appears that the existing EPA program does apply to wastes generated by lignite gasification facilities.

Footnotes - Section 4.7

- ¹ Title II, P.L. 89-272 (1965); P.L. 91-512 (1970).
- ² P.L. 94-580; 42 USC 6901 et seq. (1976).
- ³ House Committee on Interstate and Foreign Commerce, Report on H.R. 14496, 94th Congress, 2d Session (1976) at 9.
- ⁴ John Quarles, Federal Regulation of New Industrial Plants, BNA's Environment Reporter, Monograph 28 (1979) at 31.
- ⁵ Vernon's Ann. Civ. St. art. 4477-7.
- ⁶ Stephen Buchanan, The RCRA Subtitle C Hazardous Waste Regulations and Their Impact on the State of Texas, 11 Environmental Law Journal 3 (July 1980).
- ⁷ John Quarles, id. at 34.
- ⁸ 45 Federal Register 33063-33588, May 19, 1980.
- ⁹ Texas Department of Water Resources, Proposed Rules of the Texas Water Development Board Pertaining to Industrial Solid Waste Management, August 7, 1980.
- ¹⁰ 19 Natural Resources Journal 249, 250 (1979).

4.8 Toxic Substance Control

4.8.1 Introduction

The Toxic Substance Control Act (TSCA) authorizes the EPA to regulate chemical substances that present a hazard to health or the environment at their source before they are dispersed into the environment. The TSCA provisions are as follows:

- Manufacturers are required to test chemicals so that their environmental and health effects can be evaluated;
- Manufacturers of new chemical substances (and processors of old chemicals for significant new uses) are required to notify the EPA at least 90 days before production commences;
- EPA is authorized to delay manufacture until sufficient testing data is available, to restrict the use or sale of certain chemicals, or to prohibit the manufacture if the substance may cause or significantly contribute to an unreasonable risk to health or the environment;
- Manufacturers are required to conduct certain recordkeeping functions; and
- EPA is provided enforcement powers, including authority to seize chemicals and to seek injunctive relief for imminently hazardous substances.

The PMN, which must contain information about the product, is to provide the EPA with a basis for determining whether there will be "unreasonable risks" to health or the environment. If there is insufficient information available on the substance, the EPA can require test data to be developed. The 90-day review period begins as soon as a complete notice is received. This period can be extended for 180 days by EPA for good cause. At the completion of the review period, if no action has been taken by EPA, a notice that manufacturing has begun must be submitted.

TSCA provides regulatory authority that overlaps several other programs. The EPA is given discretionary powers in determining if it is in the public interest to use TSCA to protect health and the environment.

4.8.2 Performance Standards

EPA has promulgated, or is in the process of promulgating, testing requirements for certain chemicals that represent either an "unreasonable risk" or that are produced in "substantial quantities or have significant exposure to humans." If no testing rule exists, which is currently the case for synthetic fuels, the manufacturer may request that the EPA develop a proposed rule. EPA has 75 days to propose a testing rule after such a request. Chemicals can be exempted from testing requirements if it can be shown that they are "equivalent" to chemicals already tested. EPA can block manufacture of chemicals until testing is complete.

4.8.3 Permit Process

Figure 4.8-1 provides a flow chart showing the most likely decision paths that an industrial project would follow under TSCA, along with statutory time limitations. The requirement for testing of any chemical substance is discretionary on the part of EPA and is decided on a case-by-case basis. In EPA's proposed rules, Premanufacture Notification Requirements and Review Procedures (40 C.F.R. Part 720), a manufacturer may ask the EPA whether a premanufacture notice is required for a specified chemical. The EPA will answer their inquiry quickly if the manufacturer can establish a *bona fide* intent-to-manufacture the substance. This can be done confidentially and the EPA will provide a final response within 45 days. The submission of a *bona fide* intent to manufacture should be accomplished as soon as selection among alternate facility process designs make this possible. This preliminary inquiry should include the following to the extent available:

- A signed statement that the industrial submitter intends to manufacture the chemical substance;
- A description of the research and development activities the submitter has conducted to date relative to the new chemical(s) to be produced, and the purpose for manufacturing the substance(s);
- An elemental analysis;

TSCA

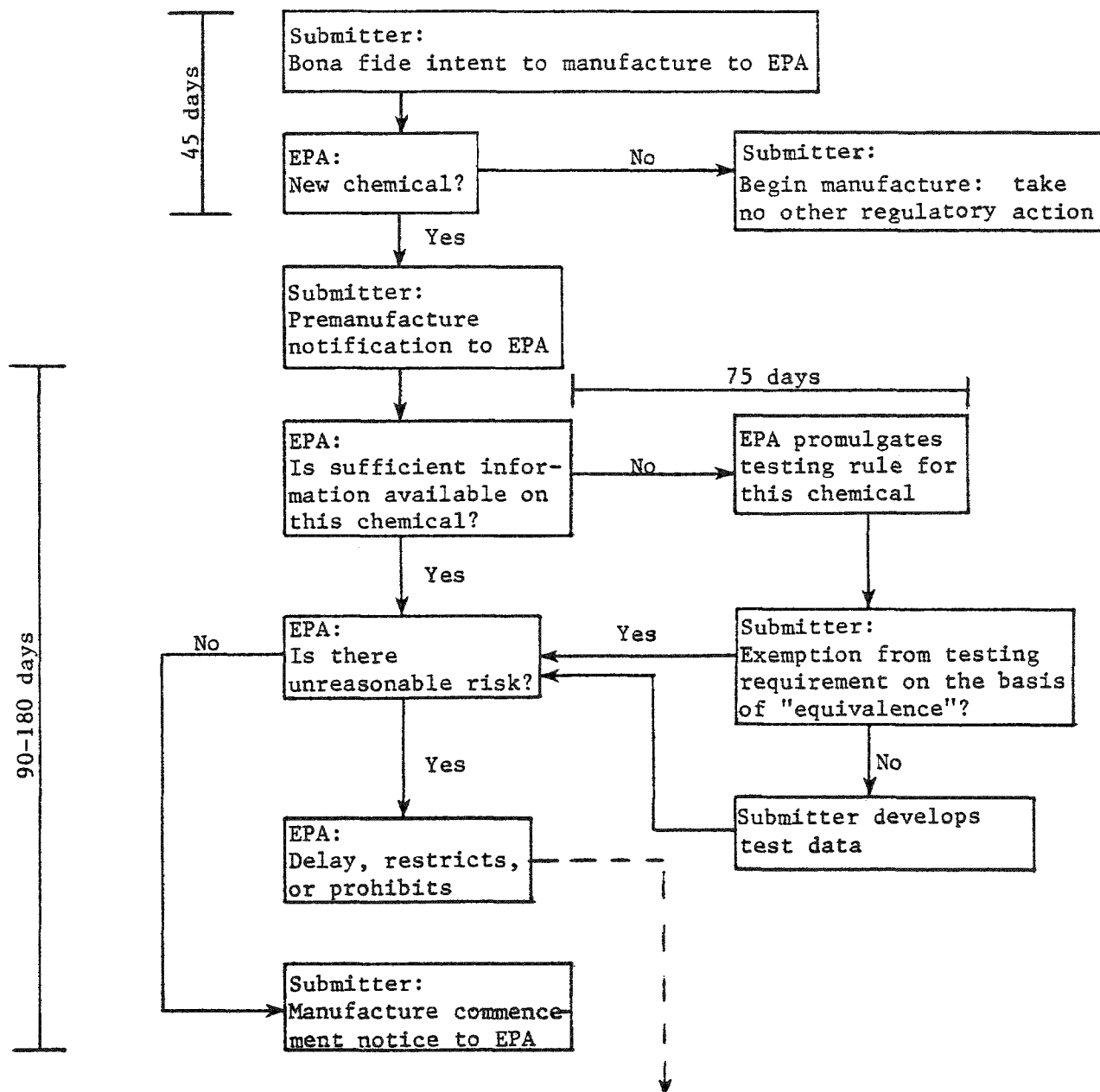


Figure 4.8-1. Flow Chart of TSCA Decision Paths

- Either X-ray diffraction pattern (for inorganic substances) or a mass spectrum (for most other substances) of the particular chemical substance, or if such data do not resolve uncertainties with respect to the identity of the chemical substance, additional or alternative spectra or other data to identify the substance; and
- If requested by EPA, a sample of the substance in its purest form.

The response that EPA will provide within 45 days will clarify the exposure of the project to regulations under TSCA. The length of the approval procedure could take a year or longer if testing is required.

4.8.4 Applicability

Depending upon what types of synthetic fuel streams are produced by the gasifier in the MBG scenario, TSCA may be present significant regulatory requirements for that scenario. TSCA will not apply to the DF scenario.

4.9.2 Fish and Wildlife Resources

4.9.2.1 Fish and Wildlife Coordination Act

The Fish and Wildlife Coordination Act (FWCA) gives the Fish and Wildlife Service (FWS) of the Department of Interior authority to be involved in federal agency decisions that may disrupt aquatic habitats. Any activity carried out by a federal agency or pursuant to a federal permit or license that would affect a navigable body of water is to be reviewed by the FWS as part of NEPA (Section 4.2), Clean Water Act Section 404 (Section 4.5.2), and Endangered Species Act (Section 4.9.2.2 below) programs. As a distinct program, the FWCA is not of major importance and is not discussed further.

4.9.2.2 Endangered Species Act

The Endangered Species Act directs the Secretary of Interior to identify fish, wildlife, and plant species that are on the verge of extinction and to establish protective regulations. Activities that will result in a "taking" of a species listed as endangered are prohibited. Department of Interior regulations include activities that would result in environmental modifications that could disrupt essential behavioral patterns of the species.⁷

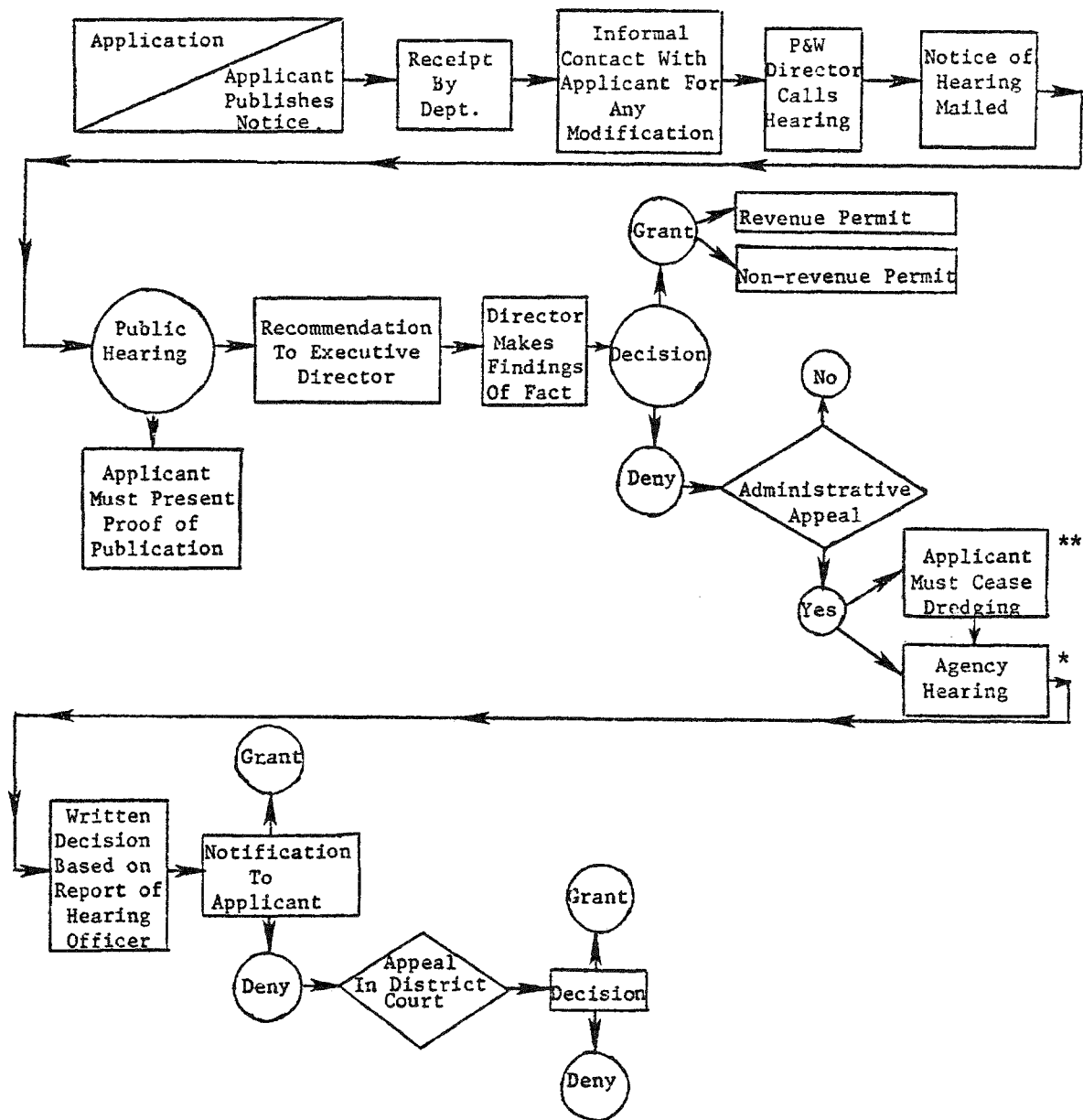
In Texas, the whooping crane and Houston toad are the only species enjoying critical habitat protection. The former is fully protected in Texas in that its habitat is confined to areas along the coast largely under federal jurisdiction (the Aransas Wildlife Refuge). The latter species is found in some counties subject to lignite development. Should direct

conflict between lignite development surface mining and critical habitat for the Houston toad occur it is possible that development would have to be foregone. The outcome of the snail darter/Telleco Dam controversy, however, demonstrates that an opposite outcome is also possible if Congress chooses to intervene in order to mandate an exception to the Act.

4.9.2.3 Texas Parks and Wildlife Code

The Texas Parks and Wildlife Code empowers the Parks and Wildlife Department (PWD) to manage the state's fish and wildlife resources. The PWD also regulates the dredging of sedimentary fill and shell materials from publicly-owned waters. Public waters include all the salt and fresh waters under the jurisdiction or ownership of the state, all lands underlying such areas, and all lands underlying the beds of navigable streams subject to jurisdiction of the Parks and Wildlife Commission.

Much of the PWD's regulatory authority involves permitting requirements. The permit having the greatest impact on development is the one required for dredging activities. Procedures for dredging permits are outlined in Figure 4.9.1. Another important permit is the one required to take, possess, transport, export, process, sell or offer for sale, or ship endangered species. This language is similar to language in the federal act discussed in subsection 4.9.2.2 and presumably has a similar effect.



* Marl, Sand, and Gravel
 ** Shell

Figure 4.9-1. Procedures for Parks and Wildlife Dredging Permits

Additional regulatory activities of the Texas Parks and Wildlife Department under the Code include:

- Enforcement of water quality standards when a violation of those standards affects aquatic life or wildlife;
- Comments to the Corps of Engineers under the Fish and Wildlife Coordination Act for permit applications involving Departmental concerns; and
- Comments to the Texas Department of Water Resources concerning state certification of Corps of Engineers dredge and fill permits under §404 of the Clean Water Act (applies only to nonpublic coastal saltwater wetlands).

Construction of new industrial facilities and pipeline construction may involve dredge and fill operations. To the extent dredge and fill activities in publicly owned waters are involved, PWD permitting authority will be invoked. PWD may also influence decisions related to other environmental disturbances caused by transportation and utilization of lignite in solid or gaseous form. This influence will be exerted by way of PWD comments upon permit applications to other agencies.

4.9.3 Cultural and Historical Resources

4.9.3.1 The Historic Sites Preservation Act

The Federal Historic Sites Act empowers the Secretary of Interior to preserve historical and archaeological data that might be destroyed through inundation of the land or by alteration of terrain. Federal agencies authorizing or building dams or other projects, or issuing licenses for private actions, that may cause irreparable loss of scientific, historic, or archaeological data must notify the Secretary. The Secretary must then take appropriate action to preserve the data. This may involve on-site data collection or removal of valued objects to unaffected sites. Either approach may involve significant delay in whatever activity is threatening the resources.

The potential loss of data is to be considered in preparation of project Environmental Impact Statements (EIS) under the National Environmental Policy Act (NEPA). (See Section 4.2). There must be a survey of possible sites during any EIS preparation.

Those phases of the two scenarios requiring federal permits, e.g. Corps of Engineers dredge and fill permits or permits under the NPDES program, will raise the issue of historic sites preservation. In this connection, it should be noted that the TSCMRA, like the federal SMCRA (see Section 4.3), provides for protection of historical resources threatened by surface mining.

4.9.3.2 Patriotism and the Flag

The Texas Patriotism and the Flag statute establishes the Texas Historical Commission. The Commission is given the broad responsibility of furnishing leadership, coordination, and services to County Historical Commissions and others who have an interest in the preservation of Texas' historical heritage. The Commission's Executive Director is designated as the State Liaison Officer and in that capacity conducts relations with representatives of the federal government and the states regarding matters of historic preservation.

Section 12 of the Act provides in Part (1) for the Commission to designate Recorded Texas Historic Landmarks. Part (2) of Section 12 provides that:

"No person may damage the historical or architectural integrity of any structure which has been designated by the Commission as a Recorded Texas Historic Landmark, without first giving 60 days' notice to the Texas Historical Commission. After receipt of notice, the Commission may waive the waiting period or, if the Commission determines that a longer period will enhance chances for preservation, it may require an additional waiting period of not more than 30 days. Upon the expiration of the time limits imposed by this section, the person may proceed, but must proceed within 180 days of the expiration of the time the notice was given or the notice shall be deemed to have expired."

This provision is intended to give the Commission an opportunity, where it deems appropriate, to collect data from, or remove to another site, a landmark threatened with destruction by, for example, a surface mine.

The Texas Historical Commission does not have permitting authority. The oversight function it performs could, however, delay any of the operations posited under either scenario.

4.9.3.3 Texas Antiquities Code

The Antiquities Code⁷ established the Texas Antiquities Commission (TAC). The TAC is responsible for protecting the state's historical and archaeological resources. Much of the TAC's responsibility relates to scientific study of archaeological sites or salvage of antiquities on lands belonging to any city, county, or political subdivision of the State of Texas. Prior to undertaking these activities, individuals are required to apply for a permit from the TAC.

More relevant here is that the TAC may require permits prior to a state approval of construction, dredging, or filling operations in the navigable waters or wetlands. The TAC reviews applications to the U.S. Army Corps of Engineers for permits under Section 404 of the Clean Water Act and Section 10 of the Rivers and Harbors Act of 1899.

Texas gives special protection to hundreds of sites listed or nominated for inclusion on the National Register of Historic Places or sites designated by the TAC as important state cultural or historical resources. Designated State Archaeological Landmarks may not be taken, altered, damaged, destroyed, salvaged, or excavated without approval by contract with or permit from the TAC.

Operators of surface mines, persons constructing pipelines or railroad spurs, and persons constructing new industrial facilities will be required to survey the proposed sites to be altered for designated historical or cultural resources. Upon identification of such resources, the individual proposing to begin excavation or construction must apply for a permit as described above.

As is the case with the other programs outlined above, the TAC program is intended to accomodate both development and protection of historic and cultural resources. It is not anticipated that permitting under the TAC program will impose any serious constraints on surface mining operations. Some rerouting of pipelines or railroad spurs might be required to preserve important historical sites. New facilities may also find some constraints placed on their siting decisions where important historical resources are present. Serious delay is not anticipated in any of these areas.

Footnotes - Section 4.9.

¹16 USC 661, et seq.

²16 USC 1531.

³16 USC 469 et seq.

⁴Vernon's Ann. Civ. St. Art. 6145.

⁵Vernon's Tx. Nat. Res. Code §191.022.

⁶Vernon's Tx. Nat. Res. Code §191.022.

⁷50 CFR Part 17.

4.10 Noise Controls

4.10.1 Federal Programs

EPA regulations (40 C.F.R. 6) implementing the National Environmental Policy Act (NEPA) specify that noise should be one of the factors considered in the description of the affected environment and in the evaluation of alternatives in an Environmental Impact Statement (EIS). Therefore, the discussion in Section 4.2, NEPA, is pertinent. Federal noise control legislation and regulations will affect the permitting of the scenarios only indirectly since they are principally concerned with worker noise exposure and the manufacture and sale of products that produce noise (transportation equipment, portable air compressors, etc.).

The Noise Control Act of 1972, besides defining a role for EPA in the regulation of noise emissions from commercial products, directed EPA to develop criteria upon which the evaluation of noise impacts could be based. These criteria, published as a guideline document rather than as a regulation, constitute an acceptable basis for review under the NEPA process. The Quiet Communities Act of 1978 which amended Section 14 of the earlier Noise Control Act, directed EPA to administer a nationwide Quiet Communities Program which would provide grants and technical assistance to state and local governments for the purpose of establishing noise control programs. Efforts under this program have been limited to pilot projects in three urban areas (Kansas City, Spokane, and Allentown, Pennsylvania) with little prospect for affecting a Central Texas lignite mine or gasification plant.

In addition to the procedural constraints which NEPA may create for both scenarios (Section 5.4), NEPA's substantive requirements may disproportionately impact the MBG scenario simply because of the program's comprehensiveness and the project's size and complexity. The project's EIS must address both direct and indirect, short- and long-term, beneficial and adverse environmental impacts, including analysis of interconnected actions and cumulative impacts. This means that the cumulative environmental and socioeconomic impacts of both the lignite mine and the gasification facility must be considered. Regionally, the mine/gasification facility in the MBG scenario necessarily will have more concentrated impacts than the mine alone hypothesized in the DF scenario. Also, the cumulative impacts of other lignite development projects in the region must be calculated and assessed. Under the DF scenario, the impacts of the lignite mine and the new lignite-fired industrial unit will probably be considered in separate EIS's, even though they are interrelated.

The commercial and regulatory newness of medium-Btu gasification technology will cause NEPA's substantive requirements to be more onerous for the MBG development strategy than for the DF strategy. Uncertainties associated with this newness are likely to create a continuing need for additional information from new sources. Where impacts are determined to be potentially significant, but are uncertain, the lead agency will utilize a worst-case approach in its environmental analysis. Because numerous aspects of a Lurgi gasifier present environmental "unknowns" at this stage of technology development, the lead agency conducting the EIS may exaggerate the impact of uncertainties in its analyses and deliberations. In contrast, the technologies associated with the direct firing of lignite are

essentially demonstrated and are, therefore, less likely to present the problem of informational gaps in the NEPA process.

5.2.2 Air Quality Impacts

5.2.2.1 MBG Scenario

Lignite Mine

Because emissions from the gasification plant will exceed the threshold level of 100 tons per year established for fuel conversion plants under the PSD regulations, the fugitive emissions from the mine in the MBG scenario must be included as a secondary source in any air impact analysis of the mine-mouth gasifier. The gasifier itself will emit 447 tons/year of TSP, which is not expected to create a significant problem. But dust emanating from haul roads, mining equipment operations, explosions, and overburden piles will create high particulate levels in the immediate vicinity of the mine, which decrease to relatively low levels within two miles of mining activities.

Whether the PSD Class II increment for TSP for the mine and gasifier site will be exceeded will depend on the location of mining activities, the borders of the mine area, and the gasifier with respect to the prevailing winds. A detailed air dispersion modeling analysis of particulate emissions will have to be performed to determine if any PSD violations of the Class II increment will occur outside the mine area. In any case, extensive dust control measures will be required for the MBG mine. Although the MBG mine's fugitive emission problem will probably not prevent construction of the

gasifier, it will probably affect siting of the facility. In other words, the PSD modeling will probably have to be done before a final site for the gasifier can be selected.

The fugitive emissions from the MBG lignite mine will not require separate construction and operating permits from the Texas Air Control Board (TACB).

Gasifier

The gasifier presents several potential regulatory problems:

- As described above, gasifier TSP emissions in combination with the lignite mine fugitive emissions may cause the PSD Class II increment to be exceeded;
- An SO₂ problem which may result from prior development of several lignite-fired facilities in the region; and
- An HC problem of unknown magnitude because of inadequate process data.

Although the TSP emissions from the gasifier are relatively insignificant, the plant will emit relatively large quantities of SO₂: 7903 tons/year. Because of the likely prior development of several other lignite-fired facilities in the general area, the entire PSD increment for SO₂ will probably not be available at some specific locations. So although the gasifier's SO₂ emissions are not expected to consume the entire PSD increment, they may exceed the available PSD increment.

depending upon the extent of prior consumption. Modeling will be required to determine the site-specific extent of SO₂ increment consumption by pre-existing sources.

The hydrocarbon emission problem is simply a problem of unknown dimensions, due to both limited process data and the undetermined status of the ozone NAAQS at the site. Such information gaps will have to be rectified before permitting.

The gasifier will require permits both from EPA and from TACB.

MBG Utilization

Utilization of MBG by existing Gulf Coast boilers presently utilizing natural gas may result in net emissions increases of TSP, SO₂, HC, and NO_x. MBG utilization in the Harris-Galveston Counties study area presents three potential regulatory problems of significant magnitude with respect to air:

- A TSP problem in portions of the study area which are nonattainment for TSP;
- An HC problem because the study area is non-attainment for ozone; and
- An SO₂ problem because of the so-called "Gulf Coast Problem."

Because significant portions of the Houston Ship Channel are classified as nonattainment for TSP, an industry seeking authorization from TACB to burn medium-Btu gas will

have to 1) obtain emission offsets of greater than 1:1, 2) apply control technology capable of achieving LAER, and 3) meet the other nonattainment area requirements. Offsets may not be readily available, and application of LAER technology may be expensive. An option would be to burn the gas only in PSD areas, but modeling will still be required to determine if the TSP emission of 410 tons/year exceeds the available PSD increment.

Although Harris and Galveston Counties are both non-attainment for ozone, offsets will be required to convert or locate a hydrocarbon-emitting facility only in Harris County. Galveston County is classified as a rural nonattainment area which means that emission offsets for the county are built into the Texas SIP. In other words, the emission reductions and offsets assumed for Harris County and the emission reductions alone assumed for Galveston County should bring Galveston County into attainment for ozone without requiring offsets for new sources in Galveston County.

The "Gulf Coast (SO₂) Problem" has been recognized by EPA and is of special significance to Gulf Coast fuel use/substitution. The problem is posed by TACB permitting during the mid-1970's of numerous gas-fired boilers along the Gulf Coast to utilize oil. If the use of oil actually occurred, modeling analyses show that PSD increments for SO₂ would be violated and that the TSP and ozone problems would be exacerbated. Instead of treating potential emission increases as baseline emissions under an expansive concept of actual emissions, EPA chose in the final PSD regulations on August 7, 1980 to calculate increment consumption on the basis of actual emissions. Many companies with dual-fuel boilers face considerable uncertainty

about whether they will be allowed to switch to oil if and when the need arises because the PSD increment for SO₂ may be consumed by other sources in the interim.

For the facility proposing to convert to medium-Btu gas under the MBG scenario, the Gulf Coast Problem means that the PSD increment for SO₂ may be rapidly consumed if the market for natural gas changes abruptly. A facility burning MBG will emit 41 tons/year of SO₂ versus 16 tons per year for natural gas. Depending on the sulfur content of oil, an equivalent size facility could emit up to 20,000 tons of SO₂ annually. It is uncertain how TACB will address the problem when the Texas SIP is revised to incorporate the new PSD regulations. In the interim, however, long-range planning for a converted SO₂-emitting facility will be problematic.

5.2.2.2 DF Scenario

The mining and railroad transportation modules under the DF scenario do not pose significant regulatory problems with respect to air quality. Because fugitive dust does not have to be modeled for PSD purposes unless the mine is associated with a major stationary source, the mine will not require PSD review unless emissions from the mine load-out facility exceed 250 tons/year. Locomotive emissions associated with the DF transportation module are not expected to have impacts on existing ambient concentrations of CO, HC, NO_x, and TSP, and, in any case, train emissions are not regulated by EPA or the state under the PSD and nonattainment programs.

The utilization module of the DF scenario does raise significant regulatory problems with respect to air quality. While these problems are essentially the same problems as those

of the MBG utilization module, they are of substantially greater magnitude. The TSP nonattainment problem, the HC nonattainment problem, and the potential SO₂ PSD problem will similarly affect the feasibility of a new lignite-fired industrial boiler, but the emissions for the DF utilization module are concomitantly larger: 821 tons/year of TSP, 10,129 tons/year of SO₂, and up to 2,180 tons/year of HC as compared with 410, 41, and 82 tons/year, respectively, for TSP, SO₂, and HC in the MBG utilization module. In addition, NO_x emissions are greater under the DF utilization module (16,425 tons/year as compared to 13,686 tons/year), and CO emissions are substantial (2,108 tons/year) under the DF utilization module as opposed to negligible under the MBG utilization module.

The incremental size of the emissions under the DF utilization module will exacerbate the problems of obtaining emission offsets and applying control technology capable of achieving LAER.

5.2.3 Water Use Impacts

5.2.3.1 MBG Scenario

Lignite Mine

The lignite mine under the MBG scenario will have several adverse water supply impacts which could cause regulatory problems for the development strategy. The construction of on-channel impoundments, the rerouting of streams, and the consumptive use of surface water for dust control will require water use permits, floodplain reclamation approvals, and dam

construction approvals from TDWR. Because springflow contributes to baseflow of creeks in the area, dewatering of the mine may also adversely impact downstream water rights. In addition, TSCMRA requires the mine operator to replace water supplies lost or diminished by surface mining activities.

The presence of the municipal water right downstream of the hypothetical lignite mine and the general lack of permanent surface water availability for appropriation in the Brazos River Basin may cause significant regulatory problems in the Texas water use permitting processes. Term permits of 10 years duration may be issued pending the full development and use of water rights in the basin, however. Another option might be to enter into a contract with a downstream water right holder to allow the impairment of the holder's water right for a certain number of years. Based on the existence of such a contract, the mine operator could obtain a water use permit from TDWR to appropriate water for mining.

Lignite mining will probably impact the porosity, permeability, and ground-water storage characteristics of the Calvert Bluff Formation, thereby lowering the water levels in nearby wells through dewatering. Because TSCMRA requires replacement of lost or diminished water supplies, it may be necessary to deepen or redrill wells tapping the Calvert Bluff Formation within one mile of the mine. The adverse impacts of lignite mining on ground water supplies may also be issues in the TSCMRA permit and NEPA processes. In addition to mandatory replacement of lost or diminished supplies, TSCMRA also authorizes the designation of aquifers as areas unsuitable for mining ("renewable resource lands") by TRC upon petition by

an affected person. If local inhabitants perceive that their ground water supplies will be adversely affected, the ground water issue could become significant in the regulatory process.

Gasifier

Surface water will not be available for appropriation to meet the process and cooling water demands of the gasifier.

Although the effect of ground-water usage by the gasifier on supplies may be an issue in the NEPA process, the usage itself will not require a water use permit or other authorization. So long as the withdrawal of ground water does not cause the subsidence of adjacent properties, a property owner or lessee is authorized to withdraw ground water for beneficial use even though it detrimentally affects the water level of nearby wells. Loss or diminution of ground-water supplies because of pumping for the gasification plant will not require replacement of supplies.

5.2.3.2 DF Scenario

The mining and transportation modules of the DF scenario do not generate additional regulatory problems with respect to water use. The lignite mine will have similar adverse impacts on surface and ground-water supplies which may create problems and delay in the TDWR water use and TSCMRA surface mining permit processes and in the NEPA process. These impacts should be less because the mine is somewhat smaller in the DF scenario than in the MBG scenario, but that fact may or may not reduce the regulatory problems associated with water use.

The DF utilization module will have a large water requirement at the utilization site on the Gulf Coast, if process, cooling, and scrubbing water requirements are included. Although ground-water resources in Harris-Galveston Counties appear to be adequate to accommodate the demand, the problems of subsidence, surface fault activation, and salt water encroachment associated with ground-water pumping in the study area may create significant problems in obtaining a permit from the Harris-Galveston Coastal Subsidence District. In the permit process, an applicant must demonstrate that surface water supplies are not available at a competitive price in order to obtain authority to pump ground water. Since the District's mandate is to reduce the historical use of ground water in Harris and Galveston Counties, it is likely that the application of a new major industrial user will be scrutinized carefully.

5.2.4 Water Quality

5.2.4.1 MBG Scenario

There are two significant regulatory problems with respect to water quality associated with the MBG scenario:

- The problem of ground-water degradation during surface mining; and
- The problem of toxic organics and trace metals in the gasifier wastewater effluent.

The problem of ground-water degradation in general is of growing concern in Texas. Although surface-water quality

in the mine area can be protected from degradation by properly designed sedimentation/detention ponds, it is less certain that ground-water quality can be protected during surface mining. The Calvert Bluff aquifers will be most directly affected because mining will occur in the Calvert Bluff Formation. The Simsboro aquifer underlying the mine area may also be affected by degraded recharge which passes through the Calvert Bluff, however.

Although significant degradation of either formation is not anticipated and what degradation occurs can be mitigated to some extent by a properly designed mining and reclamation plan, there are substantial uncertainties associated with mining and reclaiming aquifers. In addition to the stringent TSCMRA performance standards which must be adhered to during mining and reclamation, aquifers and aquifer recharge areas are subject to designation as areas unsuitable for mining ("renewable resource lands") under TSCMRA. TSCMRA also provides that degraded water supplies must be replaced by the operator.

In that the Simsboro and, to a lesser extent, the Calvert Bluff aquifers are used locally for water supplies, local inhabitants may perceive that the quality of their water supplies will be adversely affected by surface mining operations, and may create regulatory problems for the MBG scenario. In any case, uncertainties about adverse ground water quality effects may present difficulties and delay in the NPDES, Texas waste disposal, and TSCMRA permit processes.

In addition to the potential for ground-water degradation from solid waste disposal (Section 5.2.5), an intractable surface water quality problem may be presented by the trace elements and toxic organics which may be present in the gasifier

effluent even after application of BAT. Since it is unknown whether zero discharge is achievable, the uncertainty could cause additional problems and delay in the NPDES and Texas waste disposal permit processes.

5.2.4.2 DF Scenario

The DF scenario does not present the surface-water quality problems associated with the gasifier effluent, but does raise similar problems of potential ground-water degradation from surface mining. These ground-water quality problems should be somewhat less severe for the DF scenario because of the mine's smaller size and the absence of the gasifier with its large-volume solid wastes.

5.2.5 Solid Waste Impacts

5.2.5.1 MBG Scenario

Because the overburden from surface mining is expressly exempt from RCRA, the principal solid waste problem associated with the MBG scenario involves the solid wastes generated by the gasification facility. There are several aspects of the solid waste problem which may pose regulatory constraints in the Texas solid waste disposal permit and NEPA processes:

- High waste disposal volumes of gasifier ash, boiler ash, and FGD sludge may place high waste loadings on the local ground-water system;
- High waste disposal volumes will require roughly 470 acres of disposal area over a 30-year period; and

- Biological sludge from the gas liquor treatment wastewater stream, although relatively small in volume, may be declared a hazardous waste and require special handling and disposal under RCRA standards.

Although potential adverse impacts from disposal can be mitigated through proper disposal system design, site selection, disposal operations, and hydrologic monitoring, the issue of ground-water contamination is still likely to be significant in both the Texas solid waste disposal permit and NEPA processes. Its significance is likely to be magnified by public participation in the processes.

5.2.5.2 DF Scenario

As suggested in Chapter 3, the solid waste problem associated with the direct firing of lignite along the Texas Coast under the DF scenario will entail higher costs and environmental risk of ground water contamination than will the gasification module of the MBG scenario. This will be true even though the volume of wastes produced by the new lignite-fired boiler will be approximately 25 percent less than that produced by the gasification facility. The DF scenario's solid waste disposal problems which may pose regulatory constraints in the Texas solid waste disposal permit and NEPA processes are as follows:

- Relatively high waste disposal volumes of bottom ash, fly ash, and SO₂ scrubber sludge may place high waste loadings on coastal ground-water systems;

- High waste disposal volumes (1 million tons/year) will require roughly 430 acres of disposal area over a 30-year period;
- High-volume waste disposal problems are exacerbated by the highly-developed nature of ground-water resources in the Harris-Galveston Counties study area and by hurricane flooding, subsidence, and faulting potential which limit the availability of appropriate disposal sites.

These additional waste disposal siting constraints posed for the DF scenario by the Harris-Galveston Counties study area may present substantial additional problems in obtaining authority to dispose of boiler wastes. Although proper disposal system design, site selection, and ground water monitoring can mitigate adverse impacts to ground-water, it may be necessary to transport solid wastes back to the mine or to an alternate location out of the coastal area.

5.2.6 Land Use Impacts

5.2.6.1 MBG Scenario

The presence of the following factors on the site selected for the lignite mine and the gasifier could prohibit, cause significant delay, or render a site unsatisfactory for construction:

- Land in the floodplain; and/or
- Cultural or historic sites.

If the site is located in the floodplain of a county which participates in the National Flood Insurance Program, the construction of the facility must occur in compliance with local controls written to protect flood-prone areas. These controls generally require permit application for building in the floodplain to ensure that minimum building, construction, and elevation standards are met. In the case where surface mine operations are proposed in the floodway, a special plan to mitigate flood hazards for the duration of the disturbance caused by mining must be submitted. Reclamation plans would have to include an acceptable program for restoring the floodway after the termination of operation. These provisions may not be an outright prohibition to the use of any site; however, they will affect siting of the facility.

The destruction or violation of historic or cultural sites in Texas is prohibited by several acts. The Texas Antiquities Code codifies the most significant regulations. The Code states that a potential mine site or industrial facility site must be surveyed in order to retrieve historical and cultural resources. If resources are identified, a permit from the Texas Antiquities Commission must be obtained. Siting may be affected if important historical sites exist on location, but no serious delay is expected. Since most Central Texas lands have already been disturbed by forest clearing and agricultural activities, it is not anticipated that significant historic sites will be uncovered.

Other regulatory constraints affecting the use of land for the lignite mine, gasifier, pipeline, and the use of the end product are discussed separately below.

In addition to the constraints listed above, the following site-specific constraints may prohibit or delay construction. For the hypothetical site described in Chapter 3, neither of these constraints exist; however, they may be of significance to projects located elsewhere in the Texas lignite area.

- Presence of endangered species; and
- Presence of wetlands or other ecologically sensitive areas.

Several endangered species, such as the Houston toad, American alligator, and bald eagle, are found in parts of the Texas lignite area. Construction of a mine and gasifier in those counties could disrupt the habitat of these protected species and is prohibited under the Endangered Species Act. An exception to this prohibition could possibly be obtained by Act of Congress, but is unlikely to occur. Even if granted by Congress, such action would cause considerable delay to the construction phase.

Several permitting processes provide for the protection of fresh or salt water marshes, wetlands, or other ecologically sensitive areas. If these occur on the site, it may be difficult to obtain permits, such as the Clean Water Act Section 404 permit, unless the sensitive areas are adequately protected.

The construction of the MBG pipeline is not expected to be significantly constrained or delayed by land use controls. If the pipeline is given common carrier status, the rights of eminent domain will supersede other land use controls except in

populated areas. The pipeline may have to be routed so that its path will not disrupt historic sites or other sensitive areas. This should not cause significant land use problems, however. Also, a survey of historic sites along the proposed pipeline route might delay construction, but would not deter it indefinitely.

If common carrier status is not granted by TRC, right-of-way must be purchased without benefit of eminent domain and numerous permits to cross public and private lands must be obtained. This process may be lengthy, but should not prohibit construction. Public concern with regard to the transportation of toxic carbon monoxide gas in proximity to populated areas may require special consideration in pipeline routing.

5.2.6.2 DF Scenario

The land use impacts and constraints listed for the lignite mine in the MBG scenario will also affect the construction of the lignite mine for the DF scenario. The fact that the lignite mine will be smaller in the DF scenario should not be of regulatory significance.

The regulatory constraints that will significantly affect the siting of a new boiler facility near the Texas coast are similar to those affecting the MBG gasifier. These include land in a floodplain, cultural or historic sites, habitat of an endangered species, and presence of wetlands. These constraints will affect both scenarios similarly, except in the case of floodplain regulations. More restrictive regulations are written guiding the location of facilities in a coastal floodplain. For instance, regulations dictate development within the 100-year floodplain must meet stringent criteria, including elevation of

the lowest floor of any structure at or above the level of the 100-year flood. This stipulation may completely prohibit the use of some sites in the Harris-Galveston Counties study area.

The DF facility will require ample space for the storage of lignite near the plant. The likelihood of the existence of ecologically sensitive areas near the facility is substantial in the coastal area. Hence, the likelihood of having to comply with regulations affecting the protection of these areas will be much greater under the DF scenario.

5.3 Regulatory Gaps, Conflicts, and Voids

5.3.1 Regulatory Gaps

Regulatory gaps in existing law which present uncertainty to potential development are of essentially three types:

- Administrative gaps;
- Standards/criteria gaps; and
- Jurisdictional gaps.

5.3.1.1 Administrative Gaps

The unsettled state of implementation of the following joint federal-state environmental regulatory programs create the principal administrative gaps impacting both the MBG and DF development scenarios:

- NPDES program;
- PSD program;
- Nonattainment program;
- UIC program; and
- National Flood Insurance program.

Both the NPDES and PSD programs are awaiting federal delegation by EPA to TDWR/TRC and to TACB, respectively. It appears that the differences between EPA and TACB are somewhat less severe than those differences remaining between EPA and TDWR/TRC. It is anticipated that the PSD delegation will occur in the next six months, but the NPDES delegation may be a year or more in the future. The absence of NPDES and PSD delegation raises the problem of potential conflicts (Section 5.3.2) between federal and state programs regulating the same area of environmental concern. The absence of delegation, however, probably impacts both scenarios in the same manner and to the same degree.

Although the nonattainment program has been implemented and is being administered by TACB, its status of conditional approval by EPA may create problems for both scenarios. Under the conditional approval, EPA may revoke approval if the Texas Legislature fails to implement an inspection/maintenance program for vehicles in Harris County. If EPA revokes approval, no new sources may be built in nonattainment areas, which will obviously impact the DF scenario more profoundly than the MBG scenario.

At this time, the substance and procedures of the Texas UIC program are unknown because the program has not yet been submitted to EPA for approval. Pending EPA approval of the Texas UIC program, there are no dual federal-state UIC permit processes: underground injection of industrial wastes is covered by the Texas waste discharge permit program only. The absence of the UIC program impacts both scenarios in the same manner and to the same degree.

The National Flood Insurance program presents unsettled regulatory conditions for the two scenarios for two reasons:

- Not all Texas counties are presently participating in the program; and
- The program contemplates the gradual adoption of stricter land use regulations by participating entities, based on additional flood data developed by the Federal Emergency Management Agency.

Although these program conditions similarly impact both development scenarios, the DF scenario may be more severely impacted because Harris and Galveston Counties are participating entities and new sources will be subject to gradually tightening land use regulations. The Central Texas counties in the lignite belt may or may not be participating entities, which may somewhat simplify siting of the gasification plant.

5.3.1.2 Standards/Criteria Gaps

The principal standards/criteria gaps adversely impacting the scenarios are as follows:

- Lack of BAT/BACT/NSPS emission and effluent limitations guidelines for coal gasification facilities (MBG);
- Lack of BAT/BACT/NSPS emission and effluent limitations guidelines for industrial boilers (DF);
- Lack of PSD increments for NO_x and several other pollutants (MBG and DF); and
- Uncertainty on regulation of coal and lignite-fired wastes under RCRA (MBG and DF).

Although the lack of standards and criteria would appear to impact both scenarios equally, the MBG scenario will in fact, be impacted more profoundly because EPA's timetable for development of BAT/BACT/NSPS for medium-Btu gasification plants is further in the future and less certain than the development of standards/criteria for industrial boilers. Because EPA's intention is to avoid promulgating BAT/BACT/NSPS for medium-Btu gasification facilities until it has gathered data from first-generation facilities, first-generation planning will be considerably more difficult. Until standards are developed in the mid-to-late 1980's, the industry must rely on analysis of effluent limitations guidelines for processes similar to lignite gasification processes, BAT/BACT precedents for previously permitted gasification facilities (if any), and EPA's pollution control guidance documents.

In addition to the problem of lack of standards/criteria, substantial potential exists for major changes in certain regulatory programs during the 1980's under the impetus

of a new Administration and a new Congress. The Clean Air Act is particularly vulnerable to change because Congress will review the Act's purposes and structure in 1981. The National Commission on Air Quality (NCAQ) was established by the 1977 Clean Air Act Amendments to research and make recommendations to Congress for changes in the Clean Air Act. Among the changes which may be considered are the following recommendations of the NCAQ staff:

- Application of BACT for all new sources consistent with meeting ambient air standards, an approach that in attainment areas could replace the current Class II and III PSD increment system;
- A system of regional secondary standards, developed by EPA and implemented by states with the regions varying with the pollutant, and opportunity for consideration of a wide range of other effects, including energy, economic, and social impacts;
- Delegation of significant parts of implementation plans to states with acceptable programs with EPA assuming an auditing function that would replace its current position of having to review every change in a state implementation plan;
- Development of one permit procedure and one set of requirements that could be consistently applied nationwide, rooted in clear identification of BACT and procedures for expediting approvals; and

- Possible treatment of Class I areas and related visibility constraints as a "tertiary standard," with Congressional level case-by-case resolution of Class I area conflicts between energy needs and environmental constraints.

The Clean Water Act is scheduled for congressional review in 1982. Although these proposed changes would greatly simplify PSD permitting for both scenarios, their adoption and implementation also would create substantial uncertainty for new sources caught in the program transition.

5.3.1.3 Jurisdictional Gaps

The principal jurisdictional gaps--areas where assertion of regulatory authority is uncertain are as follows:

- TRC authority over MBG pipelines which determines the availability of eminent domain authority for the MBG scenario; and
- TRC/TDWR authority over wastewater discharges from the mine site, which affects both scenarios.

Unless TRC asserts jurisdiction to regulate the MBG pipeline, the pipeline operator may be unable to obtain common carrier status and eminent domain authority and may be subject to the plethora of federal, state, and local land use regulations pertaining to pipeline construction. Although TRC will likely assert jurisdiction over the pipeline, the exact statutory basis for such assertion is unclear (Section 4.3.4).

Although TRC and TDWR each have jurisdiction over wastewater discharges from the mine site, their Memorandum of Understanding (MOU) would effectively change TDWR's role from a permitting authority to an oversight authority through the issuance of statewide rules regulating surface mining. The MOU, however, has not been implemented by the promulgation of statewide rules on which rests the effectiveness of the MOU. Until the relationship between TRC and TDWR is clarified, the nature and extent of TRC/TDWR authority over wastewater discharges will remain uncertain and will negatively impact both scenarios.

5.3.2 Regulatory Conflicts

Within the field of environmental regulation and resource management control, three types of conflict are possible:

- Federal/state;
- Interagency; and
- Intra-agency.

Underlying each of these potential areas of conflict is the basic problem of synchronizing administrative efforts to control all areas of environmental pollution. This problem arises because control of one pollutant (e.g., control of air emissions) almost invariably may lead to exacerbation of control problems for some other pollutant (e.g., disposal of solid wastes). Intra-agency conflicts are typically more a function of organizational structure and personnel than of statutory responsibility and as such are not further discussed.

By the end of 1980, federal legislation and regulations had more or less completely encompassed the environmental regulatory field. A strategy of uniform national minimum standards and technology requirements, administered by the individual states under the principal guidance of a single federal agency (EPA), has mitigated some of the potential for federal/state conflict. However, frictions still exist in some areas, and may impose varying degrees of regulatory uncertainty on resource developers.

5.3.2.1 Federal/State Conflict

Although Texas has assumed full jurisdiction over surface mining and has received Phase I interim authorization over hazardous waste disposal, the potential for federal/state conflict still remains in the following areas:

- EPA's NPDES and TDWR's waste discharge permit processes;
- EPA's PSD and TACB's construction and operating permit processes; and
- COE's dredge-and-fill permit and TDWR's floodplain reclamation approval processes.

As suggested earlier, substantial procedural and substantive coordination already exists between EPA and TDWR/TACB regulatory processes. Wherever dual federal-state permit processes remain, however, the potential for conflict generates some uncertainty and delay which impacts both scenarios in the same manner and more-or-less to the same extent.

5.3.2.2 Interagency Conflict

At the federal level, interagency conflict over environmental protection has been somewhat reduced by having a single agency, EPA, assume authority for the four major federal environmental quality control programs (Clean Air Act, Clean Water Act, Safe Drinking Water Act, and RCRA). Increasingly, EPA is assuming lead agency status for EIS preparation where major projects, such as those hypothesized here, are involved. These large projects commonly involve a full range of federal permitting, several components of which may require an EIS. For example, EIS requirements may arise under both NPDES and COE 404 dredge-and-fill permitting. Procedures are presently being established whereby EPA will more or less automatically assume lead agency status under these circumstances. This will mitigate or eliminate one potential source of interagency conflict.

Another potential source of interagency conflict is where agencies, such as the Fish and Wildlife Service of the Department of Interior, possess oversight authority (i.e., the right to comment) with respect to proposed permitting by another agency such as EPA. Disagreement between two agencies in such circumstances has the potential to significantly impede the permitting process. When major projects are involved, these delays may be extremely costly--in some cases to the point of precluding development.

Unfortunately, predicting when and where these conflicts will arise is difficult. At one extreme, such conflicts are of negligible importance to a project. At the other extreme, such conflicts can be extremely significant and time-consuming. The familiar and protracted Tellico Dam/snail darter controversy

which eventually required Congressional intervention represents the most costly kind of intergovernmental conflict at the federal level.

Interagency conflict at the state level may also occur. A pertinent example is the case of a surface lignite mine. The Texas Railroad Commission (TRC) has complete authority over surface mining and reclamation in Texas. TDWR and, to a lesser extent, TACB, also exercise control over mining activities insofar as they affect water quality and water availability and quality, respectively. To the extent that these agencies may have conflicting or different goals, the potential for inter-agency conflict exists.

5.3.3 Regulatory Voids

As is apparent from Chapter 4, the field of environmental regulation with respect to impacts associated with lignite development is almost completely occupied. The single exception to this generalization is in the area of local controls capable of mitigating short-term and long-term land use impacts resulting from population growth tied to project development. Major land use impacts, discussed in Section 3.3.1.6, are primarily related to the mine and gasification facility in the MBG scenario. Lesser impacts will result from the DF scenario mine. In addition to the direct employment of these energy facilities, additional population will result from employee families, associated service industries and expanded public sector infrastructure. The hypothesized coal gasification plant and mine could generate a temporary population of almost 10,000 and a permanent population growth of 5,000. Absent extensive land use control powers, counties and municipalities

would be unable to cope with the multitude of housing and commercial land use demands generated by such population changes.

Although specific local controls over socioeconomic impacts are lacking, such impacts are considered in the NEPA environmental review process (Section 4.2). These impacts may be used by a federal decisionmaker to justify permit denial or issuance subject to mitigation measures.

5.3.3.1 Powers of Counties

The powers and responsibilities of Texas counties are limited to those specified in the state's constitution and laws. The more important responsibilities of counties are related to law enforcement, road construction and maintenance, and tax collection. Additional responsibilities related to health and social welfare, housing, community development, and solid waste management are historically more recent and substantially more limited.

Most recently, many counties have developed limited environmental protection and floodplain development controls. Commissioners' courts in all counties also have the power to adopt requirements pertaining to streets and drainage in unincorporated subdivisions.¹ Pursuant to Article 8280, building and development standards may be adopted by these courts.

The major void in county authority is ordinance-making power that would enable counties to zone and enact building codes on a county-wide basis. Bills related to county ordinance-making power have been periodically introduced in the Texas

Legislature, but have been generally unsuccessful. Authorization of such powers by the Legislature does not appear likely in the near future.

5.3.3.2 Powers of Municipalities

Municipal powers depend upon the class of incorporating charter. There are three classes:

- Cities incorporated by special law;
- Cities incorporated under the general laws of the state; and
- Cities incorporated under home rule charter.

Depending upon the Legislature's express delegation, special law cities' powers vary from case-to-case. Zoning and building code powers of general law and home rule cities are specified in Table 5.3. -1.

TABLE 5.3.-1. MUNICIPAL ZONING AND BUILDING AUTHORITY

Power	General Law Cities	Home Rule Cities
Zoning Authority	For the purpose of promoting health, safety, morals, and for the protection and preservation of places and areas of historical and cultural importance and significance, or the general welfare of the community, the legislative body of cities and incorporated villages is hereby empowered to regulate and restrict height, number of stories and size of buildings, and other structures, the percentage of lots that may be occupied, the size of the yards, courts and other open spaces, the density of population, and the location and use of buildings, structures, and land for trade, industry, residence, or other purposes; and, in the case of designated places and areas of historic and cultural importance, to regulate and restrict the construction, alteration, reconstruction, or razing of buildings and other structures [VACS Art. 1011a].	To divide the city in zones or districts and to regulate the location, size, height, bulk and use of buildings within such zones or districts, and to establish building lines within such zones or districts or otherwise, and make different regulations for different districts and thereafter alter the same [VACS Art. 1175(26)].
Building Code Authority	(8) Unclean establishment--To compel the owner or occupant of any grocery . . . or other unwholesome or nauseous house or place, to cleanse, remove or abate the same, as may be necessary for the health, comfort and convenience of the inhabitants. (9) Location of establishment--To direct the location of business tanneries, . . . and regulate the management and construction of, restrain, abate and prohibit within the city limits, slaughtering establishments and hide houses or establishments for making soap, . . . and all other establishments or places where any nauseous, offensive or unwholesome business may be carried on [VACS Art. 1015(8), (9)]. (11) Nuisances--To abate and remove nuisances and to punish the authors thereof by fine, and to define and declare what shall be nuisances and authorize and direct the summary abatement thereof; and to abate all nuisances which may injure or affect the public health or comfort in any manner they may deem expedient [VACS Art. 1015(11)].*	To provide for the establishment and designation of fire limits and to prescribe the kind and character of buildings or structures or improvements to be erected therein, and to provide for the condemnation of dangerous structures or buildings or dilapidated buildings or buildings calculated to increase the fire hazard, and the manner of their removal or destruction [VACS Art. 1175(25)].

* This specific authority may be generally interpreted to apply to many types of commercial and industrial activities. It would not seem to confer building code authority with respect to housing or service oriented establishments. Under the nuisance provision, housing standards may be effectively regulated.

The Southern Standard Building Code has been routinely adopted by numerous Texas municipalities. The Code includes standards for construction, alteration, repair, occupancy, maintenance, location, and other activities for all buildings and appurtenances. These standards are intended to secure public safety, health, and general welfare. These goals are achieved by assuring structural strength, stability, adequate light and ventilation, sanitation, and safety to property from fire and other hazards.

These municipal powers may be exercised beyond municipal limits through exercise of a city's extraterritorial jurisdiction (ETJ) powers.² Table 5.3-2 shows the geographical limits of this jurisdiction as specified by law.

TABLE 5.3-2. EXTRATERRITORIAL JURISDICTION IN TEXAS

City Population	ETJ (miles)
<5,000	0.5
5,000-25,000	1.0
25,000-50,000	2.0
50,000-100,000	3.5
>100,000	5.0

A city may annex territory within its ETJ and otherwise regulate the character and extent of development in its ETJ.

5.3.3.3 Comparison

County powers over land use are much more limited than municipal powers. Counties can, however, affect land use decisions through creative exercise of their powers

over roads and drainage and by adopting building and development standards. Municipal powers to adopt building codes, to exercise zoning power, and to extend their authority into an area of extraterritorial jurisdiction gives them much greater capability to control land use change than is present in counties. This void in land use control in Texas counties may lead to both short-term and long-term land use problems in the Texas lignite belt under either development strategy. Impacts under the MBG scenario will, however, be much greater and more immediate than under the DF scenario due to the greater socioeconomic impacts of this scenario.

5.4 Procedural Constraints

The key procedural constraints impacting both scenarios involve the NEPA EA-EIS process and the PSD ambient air quality monitoring requirement. It is difficult to say, however, which scenario will be most adversely impacted by NEPA's elaborate procedural requirements. Because of the size and complexity of the MBG gasification module and the additional substantive requirements posed by the commercial and technological newness of such project, it is likely that the EIS process will be more prolonged than that of a more routine project. On the other hand, the principal elements of the DF scenario--the lignite mine and the new lignite-fired boiler--will require separate EIS's in contrast to the single EIS required by the MBG gasification module. Separate EA-EIS procedures--scoping, studies, hearings--must be pursued in Central Texas and on the Gulf Coast which could also prolong and complicate the entire process.

The one-year PSD ambient air quality monitoring requirement is also likely to impact the MBG scenario more profoundly than the DF scenario. In the Harris-Galveston Counties study area, a consortium of industries are establishing

the Houston Regional Monitoring (HRM) network in order to provide constant ambient monitoring in areas of anticipated industrial growth. It is quite possible that an industry desiring to construct a new lignite-fired boiler might be able to take advantage of the monitoring data generated by the HRM system and avoid having to generate its own data over a one-year period. Under PSD regulations, monitors must be located at maximum impact areas based on modeling of proposed new sources. So an HRM monitor must be located in the maximum impact area of a proposed new source in order for its data to be usable. The existence of the HRM system, however, is anticipated to reduce the necessity of monitoring for each additional new source.

5.5 Conclusions

The most significant environmental impacts associated with the MBG scenario and DF scenario are socioeconomic and air quality, respectively. Correspondingly, the most severe regulatory constraint associated with the MBG scenario is the lack of county-wide land use controls, and the most severe regulatory constraint to the DF scenario is air quality regulation. Table 5.5-1 compares the relative significance of regulatory constraints for each scenario and identifies which aspect of the scenario is adversely impacted.

TABLE 5.5-1. COMPARISON OF SIGNIFICANT REGULATORY CONSTRAINTS
FOR MBG AND DF SCENARIOS*

MBG Scenario	DF Scenario
1. Lack of county-wide land use controls (mining/gasification)	1. PSD and nonattainment regulations (utilization)
2. NEPA requirements (mining/gasification)	2. Solid waste regulations (utilization)
3. Lack of BACT/BAT/NSPS emission and effluent limitations guidelines (gasification)	3. NEPA requirements (mining/utilization)
4. Water quality regulations (mining/gasification)	4. Water quality regulations (mining/utilization)
5. Solid waste regulations (gasification)	5. Water use regulations (mining/utilization)
6. PSD and nonattainment regulations (utilization)	6. Lack of BACT/BAT/NSPS emission and effluent limitations guidelines (utilization)
7. Water use regulations (mining)	
8. Ambiguous jurisdiction of TRC over MBG pipelines (transportation)	

* In order of relative significance.

Footnotes - Chapter 5

¹ Tex. Rev. Civ. Stat. Ann. Arts. 2372k and 8280-13.

² Tex. Rev. Civ. Stat. Ann. Art. 970a(3).

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Appendix A
SURFACE MINING PERMIT REQUIREMENTS

APPENDIX A. SURFACE MINING PERMIT REQUIREMENTS

Minimum requirements	Performance standards
I. General requirements for surface mining permit	
A. Identification of interests and compliance information	
1. Identify applicant	
2. Identify property interest in proposed site	
3. Identify legal entity status of applicant and property interests (officers, shareholders, assumed names)	
4. Identify current or previous coal mining permits in U.S. since 1970	
5. Identify property interests in areas contiguous to proposed site	
6. State whether applicant had federal or state surface mining permit revoked in last 5 years or forfeited mining bond (details)	
7. List each violation notice of federal or state laws and regulations received in connection with any surface coal mining operation in last 3 years (details)	
B. Right of entry and operation information	
1. Describe legal documents on which right of entry to conduct surface mining operation is based	
2. Provide written consent or conveyance of mineral interest from surface owner if mineral estate severed from surface estate	
C. Relationship to areas designated unsuitable for mining	
1. State whether proposed site within area so designated or under study for designation	
2. Provide a waiver of owner of owner dwelling if mining within 300 feet of dwelling	
D. Provide certificate of liability insurance for personal injury and property damage	
E. Provide a list of all other licenses and permits needed by applicant to conduct surface mining operations (details)	
F. Identify public office (county clerk) where copy of application will be filed for public inspection	
G. Provide a copy of newspaper advertisement of application and proof of publication	
II. General environmental resources information	
A. Describe size, sequence and timing of subareas of mine plan area	
B. Describe nature of cultural and historic resources listed or eligible for listing on National Register of Historic Places and known archeological features within mine plan and adjacent areas	
C. Describe geology, hydrology and water quality and quantity of all lands within mine plan area, adjacent area and general area	
1. Describe geology of mine plan area down to and including first aquifer below lower coal seam to be mined	

APPENDIX A. (Continued)

Minimum requirements	Performance standards
2. Collect and analyze test borings and core samples from permit area down to and including stratum immediately below lowest coal seam to be mined 3. Describe ground water hydrology of area (recharge, storage and discharge characteristics of aquifers, water quality and quantity) 4. Describe surface water hydrology of area (minimum, maximum and average discharge conditions, water quality information) 5. Identify extent to which mining operation may result in contamination, diminution or interruption of surface water source for beneficial uses 6. Identify alternative water sources which could be developed to replace existing sources	
D. Describe climatological factors typical of mine area	
E. Provide map which shows existing vegetative types and describes plant communities in mine plan area	
F. Provide study of fish and wildlife and their habitats in mine plan and adjacent areas	
G. Provide soil survey information	
H. Land-use information	
1. Provide map and supporting narrative of existing land uses 2. Provide a narrative of land capability and productivity 3. State whether mine plan area was previously mined (details) 4. Describe existing land uses and land use classifications under local law, if any, of mine plan and adjacent areas	
I. Maps	
1. Show boundaries of lands and names of present owners in mine land adjacent areas 2. Show boundaries of lands on which applicant has right to enter 3. Show all areas affected by mining activities and subareas of plan 4. Show location of buildings within 1000 feet of permit area and of surface and subsurface man-made features 5. Show boundaries of proposed reference area for determining success of revegetation 6. Show locations of water supply intakes for surface water users within relevant hydrologic area 7. Show public roads in or within 100 feet of mine plan area 8. Show boundaries of public parks and locations of cultural or historical resources 9. Show public or private cemeteries and Indian burial grounds 10. Show land which is within boundaries of units of National System of Trails or Wild and Scenic Rivers Systems	
J. Cross sections, maps and plans	
1. Show elevations and locations of test borings and samplings 2. Show elevations and locations of monitoring stations used to gather information and water quality and quantity, wildlife and air quality	

APPENDIX A. (Continued)

Minimum requirements	Performance standards
3. Show nature, depth and thickness of coal seam to be mined, seams above seam to be mined, each stratum of overburden and stratum below lowest coal seam to be mined 4. Show coal crop lines 5. Show location and extent of active, inactive or abandoned underground mines 6. Show location and extent of sub-surface water 7. Show location of surface water bodies and irrigation ditches 8. Show location and extent of existing or previously surface-mined areas 9. Show location of existing spoil and waste disposal areas, dams, impoundments and water treatment and air pollution control facilities 10. Show location and depth of gas and oil wells 11. Show slope measurements to adequately represent existing land surface configuration K. Prime farmland investigation 1. Conduct pre-application investigation of mine plan area 2. If investigation establishes lands as not prime farmlands, submit request for negative determination 3. If investigation establishes lands as prime farmlands, contact U.S. Soil Conservation Service to determine if soil survey exists and whether applicable solid map units have been designated as prime farmlands	
III. Reclamation and operation plan A. General requirements 1. Describe type and method of mining procedures, proposed engineering techniques, anticipated annual production and major equipment 2. Describe construction, modification, use, maintenance and removal of dams, embankments and impoundments; overburden and topsoil; coal removal; spoil, coal-processing waste and non-coal waste; mine facilities; and water and air pollution control facilities	<u>Pipelines</u> 1. Identify and describe pipelines in permit area and within 100 feet thereof in application 2. Visibly mark location of pipelines at 200 foot intervals 3. Insure a minimum of six feet of compacted material between pipeline and any haul road or access road 4. Do not create cut within 100 feet or one times the depth of the cut (whichever is greater), of any pipeline 5. Do not conduct blasting within 500 feet of pipeline 6. Comply with Safety Regulations for Gas Pipeline Facilities <u>Slides and other damage</u> 1. Provide an undisturbed natural barrier beginning at elevation of lowest coal seam to be mined and extending from out-slope for such distance needed to assure stability

APPENDIX A. (Continued)

Minimum requirements	Performance standards
	2. Notify Commission and comply with remedial measures if slide occurs which has potential adverse affect on public property, health, safety or environment <u>Coal-processing waste banks</u> 1. Haul or convey and place coal processing waste in new and existing disposal areas approved for that purpose 2. Dispose of coal processing waste materials from activities located outside permit area only if approved by Commission
B. Operation plan: existing facilities 1. Describe existing structure to be used in connection or to facilitate mining (details) 2. Provide compliance plan for existing structures to be modified or reconstructed for use in mining operations	
C. Operation plan: blasting 1. Describe types and amounts of explosives; procedures, sequence and timing of blasting 2. Describe blasting warning and site access control equipment and procedures 3. Describe blast monitoring equipment and procedures 4. Describe plans for recording and reporting results of preblasting surveys 5. Describe unavoidable hazardous conditions requiring deviations from blasting schedule	<u>Use of explosives</u> 1. Comply with all applicable state and federal laws in use of explosives. Conduct blasts that use more than five pounds of explosive for blasting agent in accordance with published and mailed blasting schedule 2. Conduct blasting operations with experienced, trained, competent and validly certified persons who understand hazards
D. Operation plan: maps and plans (prepared by P.E.) 1. Show lands proposed to be affected throughout the operation, in sequence of mining and reclamation 2. Show buildings, utility corridors and facilities to be used 3. Show area of land for which performance bond posted 4. Show coal storage, cleaning and loading area 5. Show topsoil, spoil and waste storage areas 6. Show water diversion, collection, conveyance, treatment, storage and discharge facility 7. Show air pollution collection and control facility 8. Show source of waste and each waste disposal facility 9. Show each facility used to protect fish and wildlife 10. Show each explosive storage and handling facility 11. Show location of each sedimentation pond, permanent water impoundment, coal processing waste bank and coal processing waste dam embankment	

APPENDIX A. (Continued)

Minimum requirements	Performance standards
E. Air pollution control plan (for all projects exceeding 1 million tons of coal per year and located west of 100th meridian West longitude) 1. Provide an air quality monitoring program 2. Provide plan for fugitive dust control practices F. Air pollution control plan (for all other projects) 1. Provide an air quality monitoring program if required by Commission to provide data 2. Plan for fugitive dust control practices G. Fish and wildlife plan 1. State how the plan will minimize disturbances and adverse impacts on fish and wildlife and how enhancement will be achieved 2. If enhancement not practicable, state why not practicable 3. State how applicant will utilize impact control measures, management techniques and monitoring methods to protect or enhance threatened or endangered species, species protected by state or federal law and habitats of unusually high value (wetlands, regional areas, etc.) H. Reclamation plan: general requirements 1. Provide detailed timetable for completion of each step of plan 2. Provide detailed estimate of cost of reclamation of operations required to be covered by performance bond 3. Provide plan for backfilling, soil stabilization, compacity and grading with contour maps and cost sections	<u>Air resources projection</u> 1. Plan and employ fugitive dust control measures as integral part of site preparation, coal mining and reclamation operations. Employ fugitive dust control measures which will ensure compliance with applicable federal and state air quality standards and which are adapted to climate, existing air quality, size of operation 2. Install air monitoring equipment 3. Conduct air monitoring in accordance with approved plan <u>Protection of fish, wildlife, etc.</u> 1. Minimize disturbances and adverse impacts on fish, wildlife and related environmental values by using best available technology 2. Achieve enhancement of these resources where practicable 3. Report to the Commission the presence in permit area of critical habitat of threatened or endangered species listed by federal or state agencies of any bald or golden eagle. Design and construct power lines and other transmission facilities in accordance with guidelines set forth in Environmental Criteria for Electric Transmission System <u>Backfilling and Grading</u> 1. Follow coal removal by contour mining with rough backfilling and grading not more than 60 days or 1500 linear feet 2. Follow time schedule approved by Commission for rough backfilling and grading of open pit mine with thin overburden 3. Complete rough backfilling and grading of area strip mine within 180 days following coal removal and not more than four spoil ridges 4. Return all disturbed areas to their approximate original contour. Transport, backfill, compact and grade all spoils to eliminate all highwalls, spoil piles and depressions.

APPENDIX A. (Continued)

Minimum requirements	Performance standards
	5. Place backfilled material to minimize adverse effects on ground water, minimize off-site effect and support approved post-mining land use <u>Regrading or stabilizing rills and gullies</u> Fill, grade or otherwise stabilize all rills and gullies deeper than nine inches in areas that have been regraded and top-soiled. Reseed and replant area. <u>Topsoil</u> 1. Save topsoil and subsoil 2. Remove topsoil and subsoil separately and segregate from other material. Redistribute topsoil immediately after removal of stockpile pending redistribution <u>Revegetation</u> 1. Establish on affected land a diverse, effective and permanent vegetative cover or some seasonal variety native to area or species that support postmining land use 2. Employ methods to encourage prompt vegetative cover and recovery of productive level compatible with postmining land use <u>Coal recovery</u> 1. Maximize utilization and conservation of coal 2. Utilize best appropriate technology currently available to maintain environmental integrity 3. Minimize re-affecting land in the future <u>Casing and sealing drilled holes</u> 1. Prevent acid or other toxic drainage from entering ground or surface waters 2. Minimize disturbance to prevailing hydrologic balance 3. Ensure safety of people, livestock, fish and wildlife and machinery in mine plant and adjacent area
4. Provide plan for removal, storage and redistribution of topsoil, subsoil and other material	
5. Provide plan for vegetation (schedule, species, methods, soil testing plan)	
6. Describe measures to be used to maximize use and conservation of coal resource.	
7. Describe materials to ensure that all acid-forming and toxic materials and materials creating fire hazard are disposed of and contingency plans to prevent combustion	
8. Describe materials to scale or manage mine openings and to plug, case or manage exploration holes and other bore holes, wells, etc.	

APPENDIX A. (Continued)

Minimum requirements	Performance standards
9. Describe steps to comply with requirements of Clean Air Act, Clean Water Act and other air and water quality laws	
I. Reclamation plan: protection of hydrologic balance	<u>Hydrologic balance</u>
1. Describe measures to be taken during and after reclamation to protect quality of surface and ground water systems, rights of water users, quality of surface and ground water 2. Provide plan to control surface and ground water drainage into, through and out of plan area 3. Provide water treatment plan with proposed quantitative limits on pollutants 4. Provide plan for restoration of approximate recharge capacity of plan area 5. Provide plan for collection, recording and regathering of ground and surface water quality and quantity 6. Determine probable hydrologic consequences of project rehydrologic regime, quantity and quality of water in surface and ground water systems under all seasonal conditions	1. Minimize changes to prevailing hydrologic balance in mine plan and adjacent areas 2. Minimize changes in water quality and quantity, in depth to ground water and in location of surface water drainage channels 3. Do not exceed water quality parameters established under state and federal laws and regulations 4. Minimize water pollution and provide necessary treatment methods, with changes in flow of drainage to be preferred to use of water treatment facilities
J. Reclamation plan: postmining land uses	<u>Postmining land use</u>
1. Describe proposed use following reclamation of site, including utility and capacity of reclaimed land to support alternative uses and relationship of proposed use to existing land use policies and plans 2. Supply comments concerning proposed use by owner of surface and responsible state and local agencies	1. Restore lands in timely manner to conditions that are capable of supporting uses which they were capable of supporting before any mining or to higher and better uses 2. Ensure that postmining use is compatible with adjacent land use and with existing federal, state or local land use policies and plans 3. Prepare and submit specific plans which show feasibility of postmining land use trends and markets and that include a schedule showing how use will be developed within reasonable time 4. Provide any necessary public facilities as evidenced by letters of commitment 5. Submit specific and feasible plans to Commission which show that financing, attainment and maintenance of use are feasible 6. Design plans under general supervision of registered professional engineer 7. Ensure that proposed use will not present actual or probable hazard to public health or safety nor will it pose any actual or probable threat of water flow diminution or pollution 8. Ensure that use will not involve unreasonable delays in reclamation

APPENDIX A, (Continued)

Minimum requirements	Performance standards
	9. Obtain firm written commitment from operator or landowner to provide sufficient crop management to assure that proposed postmining cropland use remains practicable and reasonable, where cropland could require continuous maintenance 10. Ensure that sufficient water is available and committed to maintain crop production, where cropland would require continuous maintenance 11. Ensure topsoil quality and depth are sufficient to support cropland use, where cropland would require continuous maintenance
K. Reclamation plan: ponds, impoundments, banks, dams and embankments	
1. Provide general plan for each sedimentation pond, waste bank, dam or embankment within plan area 2. Provide description map, preliminary hydrologic and geologic information, assessing hydrologic impact, survey describing potential effect on structure from subsidence and schedule for detailed design plans for structures not submitted with general plan 3. Provide stability analysis of structures more than 20 feet high impounding more than 20 acre-feet of water	
L. Describe operations to be conducted within 500 feet of an underground mine	<u>Protection of underground mining</u> Do not conduct surface mining operations closer than 500 feet to any point of either an active or abandoned mine, except to extent that operations are jointly approved by the Commission, the Mine Safety and Health Administration and a state agency responsible for safety of mine workers; that activities result in improved resource recovery, abatement of water pollution or elimination of hazards to public; and that activities are designed to protect disturbed surface areas so as not to endanger any present or future operations of either surface or underground mining activities
M. Describe stream channel diversions to be constructed within mine plan area	
N. Describe measures to be use to minimize impacts on historic places and public parks and to obtain approval of Commission and other responsible agencies	

APPENDIX A. (Continued)

Minimum requirements	Performance standards
O. Describe measures to protect interests of public and landowners if applicant seeks to conduct activities within 100 feet of right-of-way of public road or to relocate road P. Disposal of excess spoil 1. Describe disposal site and design of spoil disposal structures 2. Provide results of geotechnical investigation of site 3. Provide engineering specifications for rocktoe buttresses or key-way cuts, if necessary	<u>Disposal of excess spoil</u> 1. Haul or convey spoil not needed to achieve approximate original contour to designated disposal areas within permit area 2. Place the spoil in a controlled manner to ensure that leachate and surface runoff will not degrade surface or ground waters, fill will be stable and that disposal area is suitable for reclamation and revegetation compatible with natural surroundings 3. Design fill using recognized professional standards, certified by registered professional engineer 4. Remove all vegetative and organic materials from disposal area 5. Provide slope protection to minimize face erosion 6. Rip-rap or vegetate diversion ditches 7. Locate disposal areas on most moderately sloping and naturally stable areas available 8. Place spoil in horizontal lifts in controlled manner, compacted as necessary to ensure mass stability and prevent mass movement 9. Cover and grade spoil to allow surface and subsurface drainage compatible with natural surroundings 10. Ensure that final configuration of fill is suitable for postmining land uses 11. Utilize terraces to control erosion and enhance stability 12. Construct keyway cuts and rocktoe buttresses to stabilize fill where slope in disposal area exceeds 1v:2.8h. 13. Inspect fill for stability at least quarterly throughout construction and during critical construction periods 14. Do not dispose of coal processing wastes in head-of-hollow or valley fills 15. Dispose of coal processing wastes in other excess spoil fills only if waste is non-toxic and nonacid forming and consistent with design stability of fill 16. Construct underdrain system of durable rock to prevent infiltrations of water into spoil material if disposal area contains springs, watercourses, or wet-weather seeps.

APPENDIX A. (Continued)

Minimum requirements	Performance standards
Q. Describe each road, conveyor or rail system to be constructed, used as maintained within proposed permit area (details)	17. Ensure that foundation and fill are stable under all conditions of construction and operation 18. Return excess spoil to underground mine workings
	<u>Roads: Classes I and II</u> 1. Design, construct or reconstruct, utilize and maintain Classes I and II Roads 2. Restore area to control or minimize erosion and siltation, air and water pollution and damage to public or private property 3. Ensure that Classes I and II Roads will not cause damage to fish, wildlife and related environmental values and not cause contributions of suspended solids to streamflow or to runoff outside permit area 4. Remove all Classes I and II Roads and regrade and revegetate land affected unless: 1) retention of roads is approved as part of approved postmining use; 2) Necessary maintenance is assured; and 3) Drainage is controlled 5. Design and construct Classes I and II Roads to incorporate demand for mobility and travel efficiency and anticipated volume of traffic and weight and speed of vehicles <u>Roads: Class III</u> 1. Design, construct or reconstruct, utilize and maintain Class III roads 2. Restore area to control or minimize erosion and siltation, air and water pollution and damage to public or private property 3. Ensure that Class III Roads will not cause damage to fish, wildlife and related environmental values and not cause contributions of suspended solids to streamflow or to runoff outside permit area 4. Remove all Class III roads and regrade and revegetate land affected <u>Other transportation facilities</u> 1. Design, construct or reconstruct and maintain railroad loops, spurs, surface conveyor systems, etc. to prevent damage to

APPENDIX A. (Continued)

Minimum requirements	Performance standards
	fish, wildlife and related environmental values and additional contributions of suspended solids to streamflow or runoff outside permit area - Control and minimize diminution of degradation of water quantity or quality - Control and minimize erosion and siltation - Control and minimize air pollution - Prevent damage to public or private property
IV. Requirements for permits for Special Categories of Mining	
A. Prime farmlands	<u>Prime farmlands</u>
Provide plan for mining and restoration of land, containing soil survey, map unit and representative soil profile description	- Remove soil materials to be used in reconstruction of prime farmlands soil before drilling, blasting or mining in manner that prevents mixing or contaminating materials with undesirable matter - Separately remove and stockpile A, B, and C soil horizons or other suitable soil materials in order to create final soil having equal or greater productive capacity than that which existed prior to mining; or - Remove all soil and overburden in one step, store all soil and overburden in one stockpiled material without regard to soil horizons - Measure revegetation success on basis of comparison of actual crop production from disturbed area, compared to predetermined target level of crop production approved by Commission
- Describe method and equipment to be used for removal, storage and replacement of soil - Determine moist bulk density of each major horizon of prime farmland soil in permit area - Describe location of areas to be used for separate stockpiling of soil and plans for soil stabilization - Provide documentation, if applicable, that supports use of other suitable material, instead of A, B, or C soil horizon, to obtain equivalent or higher levels of yield as non-mined prime farmlands - Provide plans for seeding or cropping final graded disturbed land and conservation practices to control erosion - Provide studies or scientific data for areas with comparable soils, climate and management which demonstrate feasibility of reclamation plan - Provide current estimated yields under high level of management for each soil map unit from USDA for each crop to be used in determining success of revegetation	

APPENDIX A. (Continued)

Minimum requirements	Performance standards
B. Operations of areas or adjacent to areas including alluvial valley floor in the arid or semi-arid areas west of the 100th meridian	<u>Operations in alluvial valley floors</u> 1. Conduct operations to preserve throughout mining and reclamation process the essential hydrologic functions of alluvial valley floors not within an affected area 2. Reestablish, throughout the mining and reclamation process, the essential hydrologic functions of alluvial valley floors within an affected area
C. In situ processing	
D. Auger mining	
E. Experimental practices mining	
F. Steep slopes	
G. Coal processing plants and support facilities not located at or near mine site or not within permit area	

Appendix B



APPENDIX B. PROCEDURAL AND SUBSTANTIVE REQUIREMENTS UNDER SUBCHAPTER G OF THE TRC COAL MINING REGULATIONS

Part	Procedural Requirements	Substantive Requirements
770	Provides for coordination of review and issuance of permits for surface operations with other state and federal permitting programs. Permit application filing deadlines. Application format and contents requirements. Permit fees.	Applicants must file at least eight months prior to commencement of surface mining operations. Renewal or revision requests must be made at least 180 days in advance. Permits are issued for an initial term of five years unless applicant justifies a longer term. Operations must be commenced within three years of permit approval. If a synfuels facility is involved, surface mining is deemed to commence at the time construction of the facility is commenced. Applications must comply with the format required by the TRC. Information must be current, clearly and concisely presented, and supported by references to technical material available to the TRC. Detailed maps and plans must be included. Applications for a proposed permit area of-- 500 acres or more..... \$1,000 499 acres or less..... \$ 500 Applications for revisions of permits..... \$ 500 Applications for renewals of permits-- within previously approved boundaries..... \$ 500 adding acreage..... \$1,000 Applications for transfer, assignment or sale of permit rights containing-- no change from previous plan..... \$ 500 change from previous plan.. \$1,000 (Continued)

APPENDIX B (Continued)

Part	Procedural Requirements	Substantive Requirements
776	Exploration involving removal of more than 250 tons requires written approval of the TRC. If less than 250 tons, party must notify the TRC of intention to explore.	Measures to be used in meeting Part 815 permanent program performance standards for exploration. These standards are intended to: - protect wildlife - protect habitat - minimize pollution - prevent erosion - otherwise minimize environmental damage Also required is: - reclamation to a condition equal to or better than pre-exploration conditions - revegetation - use of best available technology for water pollution control
778	Minimum requirements for legal, financial, and compliance matters.	See Appendix A.
779	Minimum requirements for providing environmental resources information.	See Appendix A.
780	Minimum requirements for operation and reclamation plans.	See Appendix A.
785	Provide plan for mining and restoration of land, containing soil survey, map unit and representative soil profile description.	• Remove soil materials to be used in reconstruction of prime farmlands soil before drilling, blasting or mining in manner that prevents mixing or contaminating materials with undesirable matter • Separately remove and stockpile A, B, and C soil horizons or other suitable soil materials in order to create final soil having equal or greater productive capacity than that which existed prior to mining; or • Remove all soil and overburden in one step, store all soil and overburden in one stockpiled material without regard to soil horizons
(Continued)		

391

Part	Procedural Requirements	Substantive Requirements
	Describe method and equipment to be used for removal, storage and replacement of soil. Determine moist bulk density of each major horizon of prime farmland soil in permit area. Describe location of areas to be used for separate stockpiling of soil and plans for soil stabilization. Provide documentation, if applicable, that supports use of other suitable material, instead of A, B, or C soil horizon, to obtain equivalent or higher levels of yield as non-mined prime farmlands. Provide plans for seeding or cropping final graded disturbed land and conservation practices to control erosion. Provide studies or scientific data for areas with comparable soils, climate and management which demonstrate feasibility of reclamation plan. Provide current estimated yields under high level of management for each soil map unit from USDA for each drop to be used in determining success of revegetation	• Measure revegetation success on basis of comparison of actual crop production from disturbed area, compared to predetermined target level of crop production approved by Commission.
	Operations on areas or adjacent to areas including alluvial valley floor in the arid or semi-arid areas west of the 100th meridian.	• Conduct operations to preserve throughout mining and reclamation process the essential hydrologic functions of alluvial valley floors not within an affected area • Reestablish, throughout the mining and reclamation process, the essential hydrologic functions of alluvial valley floors within an affected area

(Continued)

APPENDIX B (Continued)

Part	Procedural Requirements	Substantive Requirements
	In situ processing Auger mining Experimental practices mining Steep slopes Coal processing plants and support facilities not located at or near mine site or not within permit area	
786	Requirements for public notice, submittal of written comments and objections, public hearing and review of applications in light of comments, objections, and the public hearing record. Public agencies and "persons whose interests are or may be adversely affected may file written objections to any application within 30 days of final notice publication. A public hearing may be called by the applicant, the TRC, or any person adversely affected, within 45 days of final notice.	Notice involves publishing, in a newspaper of general circulation in the proposed mining area, an advertisement once a week for four consecutive weeks. Written notice must be submitted to: • Texas Department of Water Resources • Texas Department of Health • Texas Air Control Board • Texas Historical Commission • University of Texas Bureau of Economic Geology • Texas State Soil and Water Conservation Board • Texas Parks and Wildlife Department • Texas General Land Office • U.S. Soil Conservation Service • U.S. Fish and Wildlife Service • Office of Surface Mining-Regional Office • Other federal, state and local government agencies with jurisdiction over an interest in the area of the proposed operations • Sewage and water treatment authorities and water companies in the area, and • Federal or state governmental agencies • Federal or state governmental agencies with authority to issue all other permits and licenses needed by the applicant
787	Provides for administrative and judicial review of TRC decisions.	

Appendix C

DPA Form 3510-1 (5-90)

CONTINUE ON REVERSE

APPENDIX C. (Continued)

33556

Federal Register / Vol. 45, No. 98 / Monday, May 19, 1980 / Rules and Regulations

CONTINUED FROM THE FRONT

VII. SIC CODES (4-digit, in order of priority)											
A. FIRST						B. SECOND					
(specify)						(specify)					
C. THIRD						D. FOURTH					
(specify)						(specify)					
VIII. OPERATOR INFORMATION											
A. NAME											B. Is the name listed in Item VIII-A also the owner? ☐ YES ☐ NO
C. STATUS OF OPERATOR (Enter the appropriate letter into the answer box; if "Other", specify.)											D. PHONE (area code & no.)
F - FEDERAL S - STATE P - PRIVATE M - PUBLIC (other than federal or state) O - OTHER (specify)											A 11 12 13 14 15 16 17 18 19 20
E. STREET OR P.O. BOX											
F. CITY OR TOWN											G. STATE
H. ZIP CODE											IX. INDIAN LAND
											Is the facility located on Indian lands? ☐ YES ☐ NO
X. EXISTING ENVIRONMENTAL PERMITS											
A. NPDES (Discharges to Surface Water)						D. PSD (Discharges from Proposed Sources)					
9 N						9 P					
B. UIC (Underground Injection of Fluids)						E. OTHER (specify)					
9 U						9					
C. RCRA (Hazardous Wastes)						F. OTHER (specify)					
9 R						9					
XI. MAP											
Attach to this application a topographic map of the area extending to at least one mile beyond property boundaries. The map must show the outline of the facility, the location of each of its existing and proposed intake and discharge structures, each of its hazardous waste treatment, storage, or disposal facilities, and each well where it injects fluids underground. Include all springs, rivers and other surface water bodies in the map area. See instructions for precise requirements.											
XII. NATURE OF BUSINESS (provide a brief description)											
XIII. CERTIFICATION (see instructions)											
I certify under penalty of law that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those persons immediately responsible for obtaining the information contained in the application, I believe that the information is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.											
A. NAME & OFFICIAL TITLE (type or print)						B. SIGNATURE			C. DATE SIGNED		
COMMENTS FOR OFFICIAL USE ONLY											

EPA Form 3510-1 (5-80)

REVERSE

BILLING CODE 6890-01-C

Please print or type in the unshaded areas only
(fill-in areas are spaced for elite type, i.e., 12 characters/inch).

Form Approved OMB No. 158-S80004

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APPENDIX C. (Continued)

Federal Register / Vol. 45, No. 98 / Monday, May 19, 1980 / Rules and Regulations

32585

Continued from the front.

III. PROCESSES (continued)

C. SPACE FOR ADDITIONAL PROCESS CODES OR FOR DESCRIBING OTHER PROCESSES (code "T04"). FOR EACH PROCESS ENTERED HERE INCLUDE DESIGN CAPACITY.

IV. DESCRIPTION OF HAZARDOUS WASTES

A. EPA HAZARDOUS WASTE NUMBER - Enter the four-digit number from 40 CFR, Subpart D for each listed hazardous waste you will handle. If you handle hazardous wastes which are not listed in 40 CFR, Subpart D, enter the four-digit number/s from 40 CFR, Subpart C that describes the characteristics and/or the toxic contaminants of those hazardous wastes.

B. ESTIMATED ANNUAL QUANTITY - For each listed waste entered in column A estimate the quantity of that waste that will be handled on an annual basis. For each characteristic or toxic contaminant entered in column A estimate the total annual quantity of all the non-listed waste/s that will be handled which possess that characteristic or contaminant.

C. UNIT OF MEASURE - For each quantity entered in column B enter the unit of measure code. Units of measure which must be used and the appropriate codes are:

ENGLISH UNIT OF MEASURE	CODE	METRIC UNIT OF MEASURE	CODE
POUNDS	P	KILOGRAMS	K
TONS	T	METRIC TONS	M

If facility records use any other unit of measure for quantity, the units of measure must be converted into one of the required units of measure taking into account the appropriate density or specific gravity of the waste.

D. PROCESSES

1. PROCESS CODES:

For listed hazardous wastes: For each listed hazardous waste entered in column A select the code/s from the list of process codes contained in Item III to indicate how the waste will be stored, treated, and/or disposed of at the facility.

For non-listed hazardous wastes: For each characteristic or toxic contaminant entered in column A, select the code/s from the list of process codes contained in Item III to indicate all the processes that will be used to store, treat, and/or dispose of all the non-listed hazardous wastes that possess that characteristic or toxic contaminant.

Notes: Four spaces are provided for entering process codes. If more are needed: (1) Enter the first three as described above; (2) Enter "000" in the extreme right box of Item IV-D(1); and (3) Enter in the space provided on page 4, the line number and the additional code/s.

2. PROCESS DESCRIPTION: If a code is not listed for a process that will be used, describe the process in the space provided on the form.

NOTE: HAZARDOUS WASTES DESCRIBED BY MORE THAN ONE EPA HAZARDOUS WASTE NUMBER - Hazardous wastes that can be described by more than one EPA Hazardous Waste Number shall be described on the form as follows:

1. Select one of the EPA Hazardous Waste Numbers and enter it in column A. On the same line complete columns B, C, and D by estimating the total annual quantity of the waste and describing all the processes to be used to treat, store, or dispose of the waste.
2. In column A of the next line enter the other EPA Hazardous Waste Number that can be used to describe the waste. In column D(2) on that line enter "Included with above" and make no other entries on that line.
3. Repeat step 2 for each other EPA Hazardous Waste Number that can be used to describe the hazardous waste.

EXAMPLE FOR COMPLETING ITEM IV (shown in line numbers X-1, X-2, X-3, and X-4 below) - A facility will treat and dispose of an estimated 900 pounds per year of chrome shavings from leather tanning and finishing operation. In addition, the facility will treat and dispose of three non-listed wastes. Two wastes are corrosive only and there will be an estimated 400 pounds per year of each waste. The other waste is corrosive and ignitable and there will be an estimated 100 pounds per year of that waste. Treatment will be in an incinerator and disposal will be in a landfill.

LINE NO.	A. EPA HAZARDOUS WASTE NO. (enter code)	B. ESTIMATED ANNUAL QUANTITY OF WASTE	C. UNIT OF MEASURE (enter code)	D. PROCESSES	
				1. PROCESS CODES (enter)	2. PROCESS DESCRIPTION (If a code is not entered in D(1))
X-1	K 0 5 4	900	P	T 0 3 D 8 0	
X-2	0 1 0 0	400	P	T 0 3 D 8 0	
X-3	0 1 0 0	100	P	T 0 3 D 8 0	
X-4	1 0 0 0				Included with above

APPENDIX C. (Continued)

33586

Federal Register - / Vol. 45, No. 98 / Monday, May 19, 1980 / Rules and Regulations

Continued from page 2.

NOTE: Photocopy this page before completing if you have more than 26 wastes to list.

Form Approved OMB No. 158-S80004

EPA I.D. NUMBER (enter from page 1)										FOR OFFICIAL USE ONLY									
WASTE NO.										WASTE NO.									
1										2									
IV. DESCRIPTION OF HAZARDOUS WASTES (continued)																			
A. EPA HAZARD. WASTE NO. (enter code)		B. ESTIMATED ANNUAL QUANTITY OF WASTE				C. UNIT OF MEASURE (enter code)		1. PROCESS CODES (enter)						2. PROCESS DESCRIPTION (if a code is not entered in D(1))					
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1																			
2																			
3																			
4																			
5																			
6																			
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26																			

EPA Form 3510-3 (5-80)

- PAGE 3 OF 3
(enter "A", "B", "C", etc. behind the "3" to identify photocopied pages)

CONTINUE ON REVERSE

Continued from the front.

IV. DESCRIPTION OF HAZARDOUS WASTES (continued)**E. USE THIS SPACE TO LIST ADDITIONAL PROCESS CODES FROM ITEM B(1) ON PAGE 3.**

EPA I.D. NO. (enter from page 1)											
1	2	3	4	5	6	7	8	9	10	11	12
F											6

V. FACILITY DRAWINGAll existing facilities must include in the space provided on page 5 a scale drawing of the facility *see instructions for more detail*.**VI. PHOTOGRAPHS**All existing facilities must include photographs (*aerial or ground-level*) that clearly delineate all existing structures; existing storage, treatment and disposal areas; and sites of future storage, treatment or disposal areas (*see instructions for more detail*).**VII. FACILITY GEOGRAPHIC LOCATION**

LATITUDE (degrees, minutes, & seconds)

LONGITUDE (degrees, minutes, & seconds)

VIII. FACILITY OWNER

☐ A. If the facility owner is also the facility operator as listed in Section VII on Form 1, "General Information", place an "X" in the box to the left and skip to Section IX below.

B. If the facility owner is not the facility operator as listed in Section VIII on Form 1, complete the following items:

1. NAME OF FACILITY'S LEGAL OWNER										2. PHONE NO. (area code & no.)									
D										10 11 12 13 14 15 16 17 18 19									
3. STREET OR P.O. BOX										4. CITY OR TOWN									
E										F									
5. ST.										6. ZIP CODE									
10 11 12 13 14 15 16 17 18 19										20 21 22 23 24 25 26 27 28 29									

IX. OWNER CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and all attached documents, and that based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the submitted information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

A. NAME (print or type)	B. SIGNATURE	C. DATE SIGNED

X. OPERATOR CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and all attached documents, and that based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the submitted information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

A. NAME (print or type)	B. SIGNATURE	C. DATE SIGNED

APPENDIX C (Continued)

33586

Federal Register / Vol. 45, No. 98 / Monday, May 19, 1980 / Rules and Regulations

Continued from page 4.

Form Approved OMB No. 158-S80004

V. FACILITY DRAWING (see page 4)

SAMPLE