Hazardous waste from mining and milling of ores and minerals are the subject of a three-year study to be completed in October 1983 at which time appropriate standards and regulations may be established. In addition, if a person or facility generates less than 1,000 kg of toxic wastes in one calender month, it is exempt from the program.

Standards and Conditions. The EPA has issued three sets of standards applicable to persons dealing with hazardous waste: (1) standards applicable to generators; (2) standards applicable to transporters; and (3) standards for owners and operators of treatment, storage and disposal facilities. A brief summary of each set of standards follows.

Standards Applicable to Generators of Hazardous Waste. The generator is required to initiate a set of procedures that will ensure proper handling and ultimate disposition of a hazardous waste. Standards require specific record keeping and reporting along with packaging and labeling requirements. The heart of the generator standard is the requirement for the development of a manifest system that will provide a "tracking" system to ensure proper disposal.

Standards Applicable to Transporters of Hazardous Waste. A transporter is required to maintain compliance with the manifest system and record keeping as estabished by the generator. In addition, requirements are set forth in the event of a discharge of a hazardous waste during transportation. These standards and requirements are in addition to those established by the Department of Transportation related to shipment of hazardous materials in interstate commerce.

Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities. As of September 1981, final standards for this category had not been promulgated. The agency has issued "Interim Status Standards" (ISS). The ISS will be controlling for both existing facilities and new facilities until final standards are issued. New facility permits will be conditional subject to revision upon promulgation of final standards. Included as requirements of the ISS are: preparedness for prevention of hazards; contingency planning and emergency procedures: the manifest system; record keeping and reporting; groundwater monitoring; facility closure and postclosure care; financial requirements; the use and management of containers; and the design and operation of tanks, surface impoundments, waste piles, land treatment facilities, landfills, incinerators, thermal, physical chemical and biological treatment units, and injection wells.

Permit Application Requirements. The Resource Conservation and Recovery Act and subsequent regulations promulgated by the EPA establish a number of requirements for data and information to be submitted as a part of an Hazardous Waste permit application.

At a minimum, the following information must be submitted as a part of an application for a Hazardous Waste Management Permit:

Operator's name, address, and facility location.
Description of pollutant source and characteristics.
Existing environmental permits.
Location map and facility drawings.
Description of the business and production activity.
Description of the hazardous waste.
Process description and design capabilities.
Owner certification.
Other information as appropriate.

Permit Procedures. The following steps are part of the permit acquisition procedures.

(1) The necessary application forms and instructions can be obtained from the EPA Regional Office in which the facility will be located.

(2) A preapplication meeting with the EPA and the authorized state agency is recommended to discuss specifics of the facility and hazardous waste permit requirements.

(3) Submit the application to the appropriate EPA Regional Administrator for the area in which the facility is to be located. No application fee is required by the EPA.

(4) EPA will review the application for completeness within 30 days of receipt and request any additional information that is needed.

(5) When the application is complete, a public notice of "Receipt of Permit Application" is issued by EPA.

(6) EPA will publish the draft permit for a 30-day public comment period and hold a public hearing if appropriate.

(7) EPA will issue a final permit, modified permit, or permit denial. The permit becomes effective 30 days after issuance unless the agency receives a petition for review of any term or condition of the permit by the applicant.

(8) A permit is valid for a fixed term not to exceed 10 years.

Permit Lead Time. Under ideal conditions, the time required to process a permit application including public comment and a hearing is approximately six months.

Statutory and Regulatory Authority. The authorizing statutes are listed below.

Resource Conservation and Recovery Act of 1976 (16 USC 6901 et seq)
U.S. EPA Regulations 40 CFR Part. 122 and 124.

4.3.1.5 Coal Mining and Reclamation Permits

This is a federal-state regulatory permit program containing specific requirements for ensuring that coal mining operations are conducted in such a manner so as to minimize adverse impacts to the environment and to require reclamation of mined land. The program is authorized by the Surface Mining Control and Reclamation Act of 1977 (SMCRA) and is administered by the Office of Surface Mining (OSM), U.S. Department of the Interior, or an approved state agency. Mining and reclamation permits for coal mining on Indian lands are presently administered by the OSM.

Applicability. All surface and underground coal exploration and mining activities that extract more than 250 tons/year of coal and affect more than 2 acres require a permit. In addition, onsite processing, cleaning, and preparation of coal require permits. Coal extraction by a landowner for noncommercial use or extraction in conjunction with publicly financed highway construction are exempted.

Standards and Conditions. The SMCRA and subsequent OSM regulations set forth a comprehensive set of performance standards and requirements that must be complied with in order to minimize the adverse environmental impact of coal mining activities. At the time of the preparation of this manual, the OSM regulations were undergoing review and possible revisions. The present environmental performance standards can be summarized as follows.

General Standards:

Maximize utilization and conservation of the coal.

Reclaim areas being mined in an environmentally sound manner.
Reclaim mined areas as contemporaneously as practical with the surface coal mining operation.

Consider the physical, climatological, and other characteristics of the site in all mining and reclamation activities.

Use the best technology available.

Minimize disturbances and adverse impacts on fish, wildlife and other environmental values and enhance such resources where practical.

Restoration:

Restore the land to a condition capable of supporting land uses equal to or better than the premining uses, provided that:

such uses do not threaten water quality or availability;

such uses are reasonable, practical, and consistent with land-use policies;

such uses can be implemented in a timely manner, and

such uses are consistent with federal, state, and local law.

Restore the approximate original contour.

Exceptions to restoring original contour include:

operations which remove the upper fraction of a mountain ridge, or hill, subject to special performance standards;

operations for which the postmining use will be industrial, commercial, agricultural, residential, or public facility activities, subject to special standards and the review approval of the appropriate state, local, and other land-use planning agencies; and

operations applying for exceptions must meet special environmental performance standards.

Revegetation:

Revegetate all affected lands with a diverse, effective, and permanent vegetative cover of the same seasonal variety native to the area and capable of self-regeneration and plant succession.

Assume responsibility for successful revegetation for a period of five full years, except in areas where the annual average precipitation is equal to amounts less than 26 in. The operator will be responsible and liable for ten full years.

Waste Management:

Stabilize and protect all surface areas, including spoils piles, to control erosion and related air and water pollution.

Preserve topsoil from the mining area for revegetation program.

Restore the topsoil or best available subsoil which is best able to support revegetation.
Stabilize and revegetate all waste piles being used for the surface disposal of wastes, tailings, coal processing wastes, others.

Comply with standards developed by the Department of Interior for the design, location, construction, operation maintenance, enlargement, modification, removal, and abandonment of coal mine waste piles (consisting of mine wastes, tailings, coal processing wastes, and other liquid and solid wastes) that are used either temporarily or permanently as dams or embankments.

Dispose of all debris, acid-forming materials, or other materials that are a fire hazard in a manner that prevents contamination of water quality and sustained combustion.

Dispose of all spoils within the permit area.

Dispose of all excess spoils in a manner consistent with detailed standards that protect against erosion, contamination of water, mass movements, and other concerns.

Water Management:

Minimize the disturbances to the prevailing hydrologic balance at the mine site and in associated offsite areas.

Minimize disturbances to the quantity and quality of water in the surface water and groundwater systems during and after operations and reclamation:

avoid acid or other toxic mine drainage,

prevent additional contributions of suspended solids to the streamflow,

prevent runoff outside the permit area,

comply with all applicable federal and state laws,

clean out and remove temporary or large settling ponds or other siltation structures after areas are revegetated and stabilized,

restore the recharge capacity of the area to approximate premining conditions,

preserve the essential hydrologic functions of alluvial valley floors in the arid and semiarid areas of the country,

construct water impoundments only with the approval of the regulatory authority, and refrain from constructing roads or other access roads up streambeds or drainage channels which might alter the normal water flow.

Other Specifications:

Use explosives in a manner consistent with federal and state laws.

Submit blasting plans.

Retain records of all use of explosives.

Conduct blasting operations with persons certified by the regulatory agency.

Refrain from surface mining within 500 feet of active or abandoned underground mines, unless approved by the regulatory agency.

Construct, maintain, and restore access roads to prevent erosion, siltation, water pollution, damage to fish or wildlife or their habitat, or public or private property.

Protect offsite areas from slides or damages.

Provide for an undisturbed natural barrier to slides or erosion.

Provisions for Special Operations:

Operations on prime farm lands.

Auger operations.

Steep-slope mining operations.

Mountaintop removal.

Alluvial valley floors.

The above standards were designed to apply to coal exploration and mining on Indian lands until completion of a special study authorized by the SMCRA. After completion of the study, recommendations for legislation were made to the U.S. Congress. These recommendations if enacted would allow Indian tribes to elect to assume full regulatory authority over the administration and enforcement of regulations for surface mining of coal on Indian lands. The study was conducted by CERT in conjunction with the coal-owning tribes and a final report forwarded to the Department of the Interior in September 1979. Until the U.S. Congress enacts specific programs or requirements, all surface coal mining on Indian lands is required to comply with standards at least as stringent as those outlined above.

Permit Application Requirements. The Office of Surface Mining has not developed an application form for this program. Instead, the applicant is referred by OSM to Sections 507 and 508 of the statute which outline the information that is necessary to make application for a permit. The permit application requirements follow.

Corporate Status:

Identification of the applicant, including business status, and special data if applicant is a partnership, corporation, or other business entity.

Statement on any current or previous surface coal mining permits in the United States.

Statement on whether the applicant, any subsidiary, or affiliate or other related persons has held a federal or state mining permit within the previous 5 years which has been suspended, revoked, or similarly penalized.

Access to the Permit Area:

Names and addresses of every legal owner of record of the property (surface and subsurface) to be mined.

Names and addresses of holder of any leasehold interest in the property.

Names and addresses of any purchaser of record of the property under the real estate contract.

Names and addresses of owners of all surface and subsurface areas adjacent to the permit area.

Copy of applicant's advertisement in newspaper of general circulation which describes ownership, location, and boundaries of the site.

Statement and documents upon which applicant bases high right to enter and commence surface mining operations.
Map or plans showing:

the boundaries of the land to be affected,

boundaries of affected property owners,

man-made features of the area,

archaeological sites, and

location of all buildings within 1,000 feet of the site.

Mining Operation:

Describe type and methods of coal mining operation.

Describe engineering techniques to be used.

Describe the equipment to be used.

Describe the anticipated startup and termination dates of each phase of the operation.

State the number of acres to be affected.

Maps and plans showing land within the permit area upon which the applicant has the legal right to enter and commence operations.

Maps or plans showing:

location of spoil, waste, or refuse areas,

location of topsoil preservation areas,
location of all impoundments for waste or erosion control,

location of any settling pond or water treatment facility,

location of constructed or natural drainways,

location of any discharge into any surface body of water, and

profiles at the appropriate cross section of the final surface configuration that will be achieved under the reclamation plan.

Identify of any previous mining limits.

Identify of known underground mines.

Environmental Baseline Data: Water

Identify the watershed and location of the surface stream or tributary into which surface and pit drainage will be discharged.

Determine the probable hydrologic consequences of the operations, onsite and offsite with regard to:

the hydrologic regime, and

quantity and quality of water in surface water and groundwater system.

Collect data for the mine site and surrounding areas to enable the regulatory agency to evaluate the cumulative impacts upon the hydrology of the area, particularly on water availability (exceptions made for small operations).

Environmental Baseline Data: Geology

Cross section maps or plans of the actual area to be mined showing:

elevation and location of test borings or coal sampling nature and depth of strata of overburden,

location of subsurface water and its quality,

nature and thickness of coal or rider seam above the coal seam to be mined,

nature of the stratum below the coal seam to be mined,

all mineral crop lines and strike and dip of the coal seam to be mined, location of aquifers, and

estimated evaluation of the water table.

Environmental Baseline Data: Other

Describe climatological factors as requested by the regulatory agency.

Identify prime farm lands, accompanied by a soil sample consistent with Department of Agricultural standards.

Environmental Baseline Data: Coal Resource

State results of test borings or core samplings from the permit area including:

location of the drill holes,

thickness of the coal seam,

analysis of the chemical properties of the coal,

sulfur content of the coal,

chemical analysis of potential and/or toxic sections of the overburden, and

chemical analysis of the stratum immediately below the coal to be mined.

Reclamation Plan: General

Identify lands subject to surface coal mining operations over the life of the operations.

Identify the size, sequence, and timing of subareas for which individual permits will be sought.

Reclamation Plan: Land Use

Describe the premining land use including information on:

existing uses,

if mining has occurred previously, the use prior to that mining activity,

the capability of the land prior to mining to support a variety of uses, and

the productivity of the land prior to mining, especially with regard to classification as prime farm lands and yields of food, fiber, forage, or wood products.

Describe the postmining use of the land, including a discussion of:

the utility and capacity of the reclaimed land to support a variety of alternative uses,

the relationship of such use to existing land-use policies and plans,

the comments of any surface owners, and

the comments of any state and local governments that have the authority to regulate the proposed land use.

Describe how the postmining land use is to be achieved.

Describe the support activities that will be necessary to achieve the postmining use.

Reclamation Methods:

Describe the engineering techniques to be used.

Describe the equipment to be used.

Provide the plan for controlling surface water management.

Provide the plan for backfilling, soil stabilization, compacting, grading, and revegetation.

Provide an estimate of the costs per acre for the reclamation.

Provide a detailed timetable for accomplishing each step in the reclamation plan.

Describe the measures to be taken to protect:

the quality of surface water and groundwater systems (on and offsite),

the rights of present users to such water, and

the quantity of surface water and groundwater system (on and offsite).

Compliance with Other Standards:

Demonstrate that consideration has been given to maximizing the utilization and conservation of the coal.

Show that consideration has been given to making the operations consistent with the plans of surface mines and appropriate state and local land-use plans and programs.

Describe steps that will be taken to comply with applicable air, water, and other health and safety laws.

Describe the consideration given to developing the plan consistent with local physical, environmental, and climatological conditions.

Indicate all interest or options held by the applicant or pending interest of the applicant in lands which are contiguous to the permit areas.

In addition to the above requirements, information on subsidence control and underground placement of waste is necessary for a underground coal mine permit application. Due to the extensive nature of the application requirements, a special "Small Operators Assistance" program is available. A small operator is one that produces more than 250 tons/year of coal but less than 100,000 tons/year of coal.

Permit Procedures. The following steps are part of the permit acquisition procedure.

(1) A preapplication conference with the OSM is recommended to discuss specifics of the proposed facility and the coal mining and reclamation permit application requirements.

(2) Submit the application to the Administrator, Western Technical Center, OSM, for review along with satisfactory evidence of appropriate public notice of the filing of a permit application.

(3) OSM will review for completeness and request any additional information that may be required.

(4) Upon determination of a complete application, OSM will begin technical review and preparation of an environmental impact statement.

(5) Concurrently with OSM's review, OSM will issue a notice for public review and comment. The period for review and comment will depend on the nature and complexity of the proposal.

(6) OSM will revise or modify the draft permit as appropriate to reflect public comments and information developed as a part of the environmental impact statement.

(7) If requested, OSM will hold an informal conference on the draft permit and issue public notice of the conference.

(8) After permit application is approved but prior to issuance, the applicant will be requested to submit a performance bond. The amount will depend on the nature of the proposed coal mining and reclamation operation.

(9) Issue final permit which remains valid for up to five years or longer if circumstances warrant.

Permit Lead Time. In the past, the time required to process a permit application, once a completed application is received by OSM, was approximately 13 months. Average total time, that is time required to prepare the application, develop the EIS, and complete the technical review and public comments requirements was approximately 32 months. Utilizing the permitting schedule described in Section 4.4, the total time can be reduced substantially.

Statutory and Regulatory Authority. The authorizing statutes are listed below.

Surface Mining Control and Reclamation Act of 1977 P.L. 95-87 30 USC 1201.

U.S. Department of the Interior Regulations 30 CFR 700-800.

4.3.1.6 Underground Injection Control Permit

This is a federal-state regulatory permit program containing specific requirements for disposal of fluids by underground injection. The program is designed to protect potable groundwater and is authorized by the Safe Drinking Water Act of 1974 and the Resource Conservation and Recovery Act of 1976. The program is administered by the EPA or authorized state agency.

Applicability. A UIC permit is required for a person or facility that injects fluids into the subsurface through a bored, drilled, or driven well or through a dry well where the depth is greater than the largest surface dimension. Injection into existing wells to enhance recovery of oil and gas or to store hydrocarbons are exempt from the UIC program. EPA will administer the UIC program on Indian lands unless specific arrangements such as a cooperative agreement with the tribe has been approved.

Standards and Conditions. The UIC permit program regulates underground injections by establishing critera for five classes of wells as follows.

Class I: Wells used by generators of hazardous waste or owners or operators of hazardous waste management facilities to inject hazardous waste, other than Class IV wells. Other industrial and municipal disposal wells which inject fluids beneath the lowermost formation containing an underground source of drinking water within one-quarter mile of the well base.

Class II: Wells which inject fluids: (1) which are brought to the surface in connection with conventional oil and 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.

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.

Class IV: Wells used by generators of hazardous wastes or of radioactive wastes by owners or operators of hazardous waste management facilities or by owners or operators of radioactive waste disposal sites to dispose of hazardous waste or radioactive waste into or above a formation which contains an underground source of drinking water within one-quarter mile of the well.

Class V: Injection wells not included in Classes I, II, III, or IV.

Criteria may vary with the class of the injection well but generally include (1) well construction requirements; (2) operational requirements controlling injection volumes and pressures to ensure fluids do not migrate into any underground source of drinking water; (3) monitoring and reporting requirements; (4) plugging and abandonment procedures; (5) financial responsibilities such as a performance bond; and (6) mechanical integrity requirements to ensure well performance.

Permit Application Requirements. The Safe Drinking Water Act and the Resource Conversion and Recovery Act and subsequent regulations promulgated by the EPA establish a number of requirements for data and information to be submitted as a part of a UIC permit application. At a minimum, the following information must be submitted as part of an application for an underground injection well permit.

Operator's name, address, and facility location.
Description of pollutant source and characteristics.
Existing environmental permits.
Location map and facility drawing showing major structures and geography.
Description of the business and production activity.

Description of hazardous waste.
Process description and design capacities.
Owner certification.
Other information as appropriate.

Permit Procedures. The following steps are part of the permit acquisition procedure.

(1) The necessary application forms and instructions can be obtained from the appropriate EPA Regional Office.

(2) A preapplication meeting with EPA is recommended to discuss specifics of the facility and UIC permit requirements.

(3) Submit application to the appropriate EPA Regional Administrator. No application fee is required by the EPA.

(4) EPA will review the application for completeness within 30 days of receipt and request any additional information that is needed.

(5) When application is complete, a public notice of "Receipt of Permit Application" is issued.

(6) EPA will publish the draft permit for a 30-day comment period and hold a public hearing if appropriate.

(7) EPA will issue a final permit, modified permit, or permit denial. The permit if issued becomes effective 30 days after issuance unless the agency receives a petition for review of any term or conditions of the permit.

(8) A permit for Classes II and III wells is valid for the life of the facility but subject to review every six years. Permits for Class I and Class V wells are effective for a fixed term not to exceed 10 years.

Permit Lead Time. No specific time limit is required by the EPA other than an application should be made within a reasonable time prior to construction of a new well. For hazardous waste injection wells, an application should be filed at least six months in advance of construction.

Statutory and Regulatory Authority. The authorizing statutes are listed below.

Safe Drinking Water Act, as amended 42 USC S30f 35. et seq.
Resource Conservation and Recovery Act 16 USC 6901 et seq.

4.3.1.7 Other Potential Nonpermit Requirements

Endangered Species Act, Protection of Bald and Golden Eagles Act, Fish And Wildlife Coordination Act. Congress has enacted several statutes that are designed to give special protection of "critical habitat" for certain plant, fish, and wildlife species. All federal departments and agencies are directed to seek to conserve threatened and endangered species and to utilize their various authorities consistent with this objective. Planned facility location in an area inhabited by a species that is on the threatened or endangered species list or a nesting ground for the bald or golden eagle may preclude siting or other activities in these areas. The Fish and Wildlife Service periodically publishes a list of endangered and threatened species. The agency responsible for administering these programs is the U.S. Fish and Wildlife Service of the U.S. Department of the Interior. It should be consulted early in the siting decision process.

Floodplain Management Executive Orders 11988 and 11990, 24 May 1977. The Floodplain Management Executive Order (EO) requires all federal agencies to evaluate the potential effects of actions it may take in a floodplain to avoid adversely impacting floodplains wherever possible. The EO applies to all federal agencies that (1) acquire, manage, or dispose of federal lands and facilities; (2) undertake, finance, or assist construction and improvements; and (3) conduct activities and programs affecting land use, including planning, regulating, and permitting or licensing. Each agency (Corps of Engineers, EPA, Department of

Energy, Department of the Interior) has developed its own set of rules for implementation. In general, they are designed to create a consistent government policy against floodplain development under most circumstances. The proposed location of an energy facility within a floodplain will raise questions regarding federal issuance of a permit or financial aid. Information concerning the EO can be obtained from the Water Resources Council or the individual federal agencies.

National Historic Preservation Act, Archaeological Resource Protection Act of 1979, Antiquities Act of 1906 and Historical Preservation Act of 1974, Executive Order 11593, Protection and Enhancement of the Cultural Environment. These statutes and executive orders provide for the preservation of historic, architectural, archaeological, and cultural resources of the nation. They also provide for the development and maintenance of a "National Register" of the nation's historic and cultural heritage. In addition, consideration is given to archaeological investigations and salvage of cultural resources primarily in areas threatened by federally supported construction programs. All federal agencies are required to consider impacts of their activities, projects, or permits upon sites listed on the "National Register" as well as possible impacts on other archaeological sites. This is particularly important with regard to energy development on Indian lands because of the extent of archeological sites on many reservations. Any new project should provide for initial archaeological studies prior to final siting decisions. The program at the federal level is administered by the U.S. Department of the Interior.

Wild and Scenic Rivers Act. The Wild and Scenic Rivers Act enacted on 2 October 1968 declared that certain selected rivers of the nation, which possess outstandingly remarkable scenic, recreational, geologic, fish and wildlife, historic, cultural, or other similar values, shall be preserved in free-flowing condition and that they and their immediate environments shall be protected for the benefit and enjoyment of present and future generations. Many of the rivers that have been designated or are proposed to be designated are located in the western United States and may be indirectly or directly affected by proposed major industrial activities. A federal agency that administers programs of assistance, construction, or permits is required to ensure that such administration does not adversely affect designated rivers or adjacent lands. Certain energy facilities or supporting structures and projects could be prevented from locating on adjacent lands of wild and scenic rivers. Certain segments of major western rivers such as the Missouri, Rio Grande, Snake, and Salmon have been designated as wild and scenic with others, such as segments of the Flathead, Green, and Gunnison rivers being proposed for designation.

Toxic Substances Control Act (TSCA). The general intent of TSCA is to regulate commerce and protect human health and the environment by requiring testing and necessary use restrictions on certain toxic chemical substances. The EPA has identified approximately 55,000 chemical substances that fall within regulation by TSCA. It is possible that some of the products or byproducts of an energy production facility may be toxic and, if so, will fall under the requirements of testing and premarket/manufacture notification. In addition, the EPA has established specific regulations on polychlorinated biphenyls (PCB) and chlorofluorocarbons. Since PCBs have been widely used in electrical transformers and capacitors, and mining equipment, it is important that any energy mining, milling, and processing facility be acquainted with and in compliance with these requirements. In general, the agency has banned the manufacture, processing, or distribution in commerce of PCBs. However, existing "totally enclosed" uses can continue for the life of the equipment. Disposal is also controlled by federal regulations.

Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA). Another environmental statute that requires major industrial facilities to comply with certain environmental regulations is FIFRA. Major facilities from time to time may undertake efforts to bring under control certain undesirable vegetation and insect or rodent infestation. Controls may involve highly toxic pesticides being applied to large areas of land or in some cases surface waters. The purpose of FIFRA is to ensure that pesticides are used in a safe manner and do not pose threats to the public or natural environment. Pesticides are registered for certain uses under controlled conditions. Application must adhere to these conditions. Under certain circumstances, application of a pesticide may require the applicant to be certified by the EPA and to keep certain records. Consultation with the Regional Office of the EPA is recommended.

Energy Supply and Environmental Coordination Act, Power Plant and Industrial Fuel Use Act. These statutes are designed to assist in meeting the nation's essential needs for fuels in a manner which is consistent to the fullest extent practicable, with the national commitment to protect and improve the environment. The statute prohibits new power plants and certain large industrial boilers, exceeding 100-M Btu/hr capacity, from the use of oil or natural gas as their primary energy source unless a special exemption is obtained. The program is designed to stimulate the use of coal as the primary energy source. In most cases, this statute would preclude the construction of an oil or natural gas fired power plant or large boilers to generate steam associated with a major industrial complex on an Indian reservation. The program is administered by the Department of Energy's Economic Regulatory Administration. Information can be obtained from the Department of Energy's area offices.

Other Federal Requirements. There are other federal laws that may impact permitting of energy facilities on Indian lands and that are not directly related to environmental protection. They may, however require some environmental analysis and ultimately result in environmental conditions being made a part of any final approval or authorization. A partial listing of these requirements and the administering agency follows.

Certificate of Public Convenience and Necessity—Interstate Commerce Commission/Federal Power Commission.

Explosives User's Permit or License—Bureau of Alcohol, Tobacco, and Firearms, Department of Treasury.

Notice of Proposed Construction or Alteration of Objects Affecting Navigable Airspace—Federal Aviation Administration, Department of Transportation.

Regulations Related to Occupational and Mine Safety and Health—Department of Labor.

Special Land Use or Rights-of-Way—Various federal land management agencies.

Certificate for Consideration of Pipelines—Federal Energy Regulatory Commission, Department of Energy.

Water Service Contract—Bureau of Reclamation, Department of the Interior.

Resource Leasing and Exploration Permits—Bureau of Indian Affairs, Bureau of Land Management and Mineral Management Service, Department of the Interior.

4.3.1.8 National Environmental Policy Act

The National Environmental Policy Act (NEPA) was enacted in 1969 and has been the most significant piece of legislation dealing with environmental matters. The act declares a national policy to encourage productive and enjoyable harmony between man and his environment to promote efforts which will prevent or eliminate damage to the environment and biosphere and stimulate the health and welfare of man and to enrich the understanding of the ecological systems and natural resources important to the nation.

The single most important feature of NEPA is that it requires all agencies of the federal government to prepare detailed "Environmental Impact Statements" (EIS) on major federal actions, programs, leases, projects, or permits that significantly affect the quality of the human environment. The EIS must consist of a detailed statement on:

the environmental impact of the proposed action;

any adverse environmental effects which cannot be avoided if the proposal is implemented;

alternatives to the proposed action;

the relationship between local and short-term uses of man's environment and the maintenance and enhancement of long-term productivity; and

any irreversible and irretrievable commitments of resources which would be involved in the proposed action if it is implemented.

In most cases, major energy projects on Indian lands will require an EIS. The federal agency that is designated as the lead agency responsible for the major action associated with the project is responsible for preparing the EIS consistent with its own regulations and those promulgated by the President's Council on Environmental Quality (CEQ). For Indian lands, this agency is usually the Bureau of Indian Affairs. The agencies often will contract for the preparation of these statements. The major environmental permit programs and their applicability to NEPA and the possible requirement for an EIS are shown in Table 4.3.1-4.

Fulfilling the federal NEPA requirements and preparation of an EIS can be a very time-consuming effort. Consistent with guidelines prepared by the CEQ, the requirements have been designed to assure full opportunity for review and participation by interested parties. Both the draft and final EIS must be reviewed by any federal agency which has jurisdiction over any environmental impact involved. All interested state and local agencies must also be given a chance to review and comment. In addition, the EIS must be made available to members of the general public and, in appropriate cases, a public hearing is to be held. This open process exposes a project to a full range of public and political scrutiny as well as potential judicial attack. At a minimum, the time required to prepare an EIS is 18 months. However, large controversial projects will take significantly longer periods of time.

TABLE 4.3.1-4

ENVIRONMENTAL PERMIT PROGRAMS AND THEIR RELATIONSHIP TO THE NATIONAL ENVIRONMENTAL POLICY ACT

Environmental Permit or License	Applicability to NEPA
National Pollutant Discharge Elimination System Permit	New sources are subject to NEPA and the EIS requirements if the permit is to be issued by EPA.
404 Dredge and Fill Permit	Subject to NEPA and the EIS requirements.
Underground Injection Control Permit	Exempt from NEPA and the EIS requirements.
Prevention of Significant Deterioration Permit	Exempt from NEPA and the EIS requirements.
Hazardous Waste Management Permits	Exempt from NEPA and the EIS requirements.
Coal Mining & Reclamation Permits	Subject to NEPA and the EIS requirements.
Radiation Source Materials License	Subject to NEPA and the EIS requirements.

4.3.2 Tribal Permits

Tribal requirements are somewhat difficult to evaluate at present. The Crow Tribe has adopted an Environmental Health and Sanitation Ordinance which covers water supply, air quality, solid waste, and other health-related matters. However, this ordinance applies primarily to small-scale residential or community development. It is not yet designed to regulate environmental effects of large-scale industrial facilities. Additionally, some of the standards in the ordinance are inconsistent with current federal requirements. For example, the ordinance requires community water supplies serving 25 or more homes to meet the 1962 U.S. Public Health Service Drinking Water Standards. These have been supplemented and strengthened by the current Environmental Protection Agency standards. Moreover, the ambient air quality standards are not as comprehensive as federal or state standards. The tribal code fails to include standards for carbon monoxide, ozone, nitrogen oxides, and hydrocarbons, all of which are major pollutants.

The Crow Tribe has also adopted a Reclamation Code to govern surface mining of coal. Although the Crow Office of Reclamation is currently developing regulations and technical capabilities for administration, the Code is not yet in force. According to Section 302 of the Code, regulations first must be adopted by the Crow Tribal Council before permit requirements go into effect.

The Crow Tribe may promulgate additional environmental requirements prior to development of major industrial facilities on the reservation. The tribe has received or is in the process of negotiating grants with federal agencies for development of tribal capabilities to administer environmental programs. In 1982, the tribe recieved a grant of $30,218 from the Environmental Protection Agency to develop an areawide water quality management program under Section 208 of the Clean Water Act. This project could include development of water quality standards, if the tribe chooses to do so. Additionally, the Crow Tribe has requested funding under Section 103 of the Clean Air Act to establish an Air Quality Office and conduct air quality monitoring on the reservation. These steps may lead to adoption of more comprehensive air quality regulations. Lastly, the tribe plans to enter into a cooperative agreement with the Office of Surface Mining for funding of the Crow Office of Reclamation, technical training, and development of regulations.

Large volumes of solid waste may result from the coal gasification facility. Principally, these wastes will be ash discharged from the gasifiers and bottom ash, fly ash, and flue gas emission waste from the steam generators. It is anticipated that these wastes will be nonhazardous thus not requiring a permit under Subtitle C of the Resource Conservation and Recovery Act. Even if certain ashes are considered hazardous under EPA regulations, only those ashes from the gasifiers would require a permit. The 1980 Amendments to RCRA defer fly ash, bottom ash, slag, and flue gas emissions control waste from fossil fuel stream generators from the subtitle C program pending completion of an EPA study. Future regulation is a possibility.

Regulation of nonhazardous solid waste under Subtitle D is left totally with the states and presumably to tribal governments. Sections I, II, and IV of the Environmental Health and Sanitation Ordinance for the Crow Reservation relate to the permitting and licensing of business establishments and waste disposal facilities and may provide some authority and regulatory framework covering solid waste disposal from the synfuel facility. Clearly, however, this Ordinance was not designed to address the type of solid waste problem associated with a coal gasification process. In the absence of clear regulatory authority over nonhazardous solid waste disposal, the mitigation of possible environmental impacts can best be addressed through a complete analysis as a part of the Environmental Impact Statement process under NEPA.

4.3.3 State Permits

As discussed in Section 4.2.2, the applicability of state environmental regulations to activities on Indian reservations depends on a site-specific and development-specific analysis of facts. The analysis should explore the involvement of non-Indians in the development, the location of the development, the relationship between the attempted state regulation and federal regulatory schemes, and the effect of the attempted regulation on the tribe's right of self-government. It is impossible at this stage of the project to predict with any accuracy which state regulations might apply. It must be emphasized, however, that the coal gasification project is a major project that can create significant environmental as well as social and economic impacts and will generate considerable interest and perhaps direct involvement of state and local governments. It is strongly recommended that the appropriate state and local officials be involved early in the environmental permitting process to ensure that possible off-reservation impacts are addressed.

4.4 REGULATORY DECISION SCHEDULE

To build a decision schedule, numerous elements must be combined. The procedures and deadlines set forth in statutes and regulations comprise the foundation. They are different for each permit, and in most cases, except for the PSD permit which has a statutory deadline of one year following the filing of a complete application, there is no limit on the timing for issuance. However, both the CEQ regulations governing the NEPA process and the EPA permit regulations, which include NPDES and hazardous waste permits, provide for the establishment of project decision schedules to encourage timely decision making. Additionally, agency policy and actual practice further delimit procedures and timing.

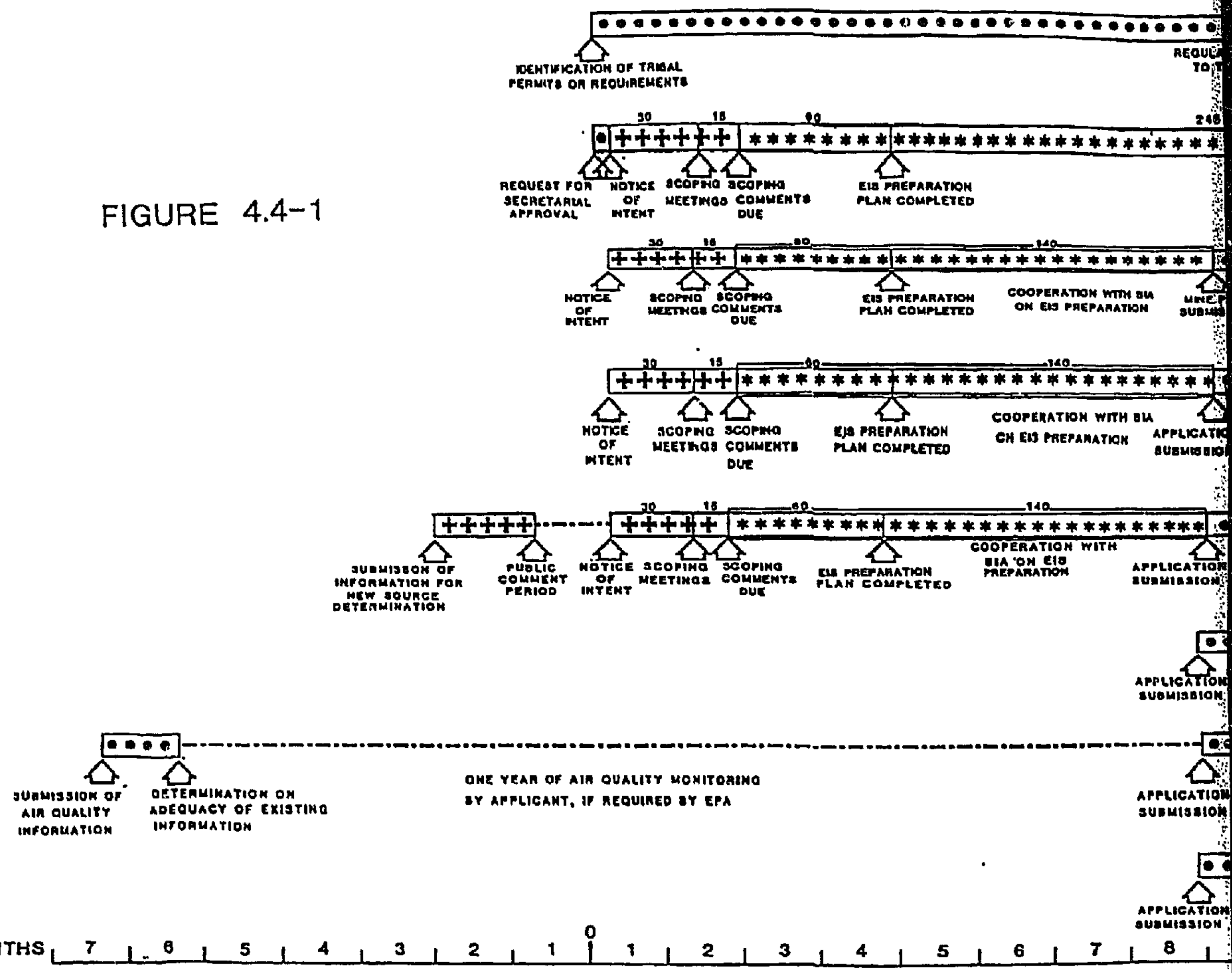
The decision schedule in Figure 4.4-1 illustrates the close linkage of timing for the EIS and various permits. An EIS is the cornerstone of the decision schedule. Because the EIS evaluates alternatives and may be a prerequisite to several federal decisions on the synfuels project, it should be prepared as early as possible. An early start is also recommended because the EIS process is a lengthy one. Submission of applications for all required permits occurs, in the decision schedule, about eight months after the EIS process begins.

The EIS process normally should be started well before permit applications are submitted. This allows preliminary evaluation of impacts and alternatives prior to commitment to specific permit options. Furthermore, under the decision schedule, the applicant submits permits prior to agency review of the preliminary draft EIS, allowing agencies to evaluate the permit application and the EIS together. The schedule assumes that no formal public hearings on permit decision will be held until the final EIS has been prepared; therefore, the final EIS serves as an important tool in the decision-making process.

Preparation of a single EIS for the synfuels project, as shown in the decision schedule, is a prime area for consideration and increased efficiency in the review process. If a single EIS is used, the Bureau of Indian Affairs would probably assume primary responsibility for preparation. Other federal agencies would work with BIA on a cooperative basis, rather than preparing their own EIS.

ENVIRONMENTAL PERMITTING

FIGURE 4.4-1



KEY

SUBMISSION OF INFORMATION

PARTICIPATION BY CROW TRIBE, AGENCIES, AND THE PUBLIC

STAFF REVIEW

DECISION

NUMBERS ABOVE EACH LINE INDICATE THE APPROXIMATE TIME PERIOD IN DAYS FOR EACH SEGMENT

REGULATORY PREAPPLICATION MONITORING

COOPERATION IN PREPERA

BIA BUREAU OF INDIAN AFFAIR

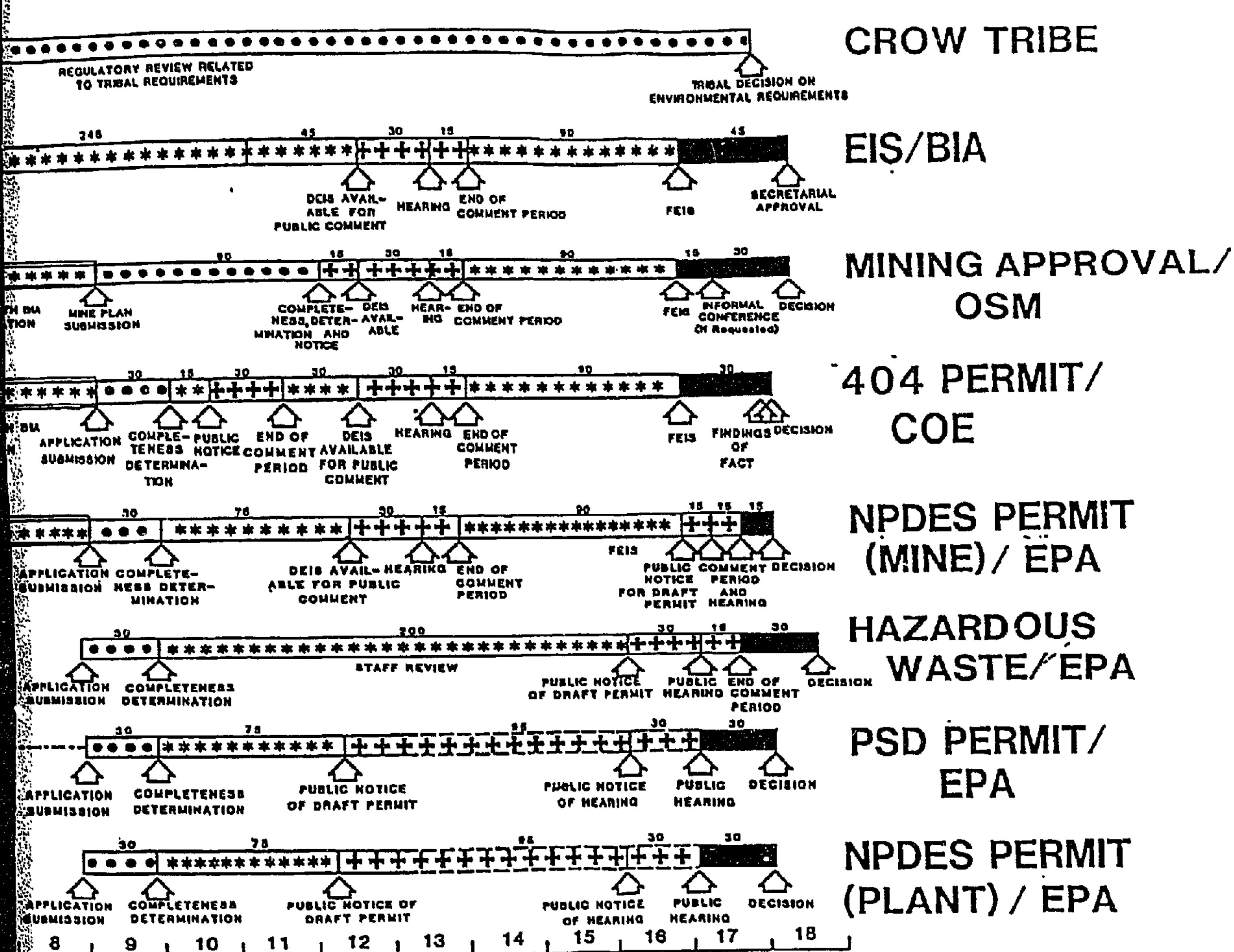
EIS ENVIRONMENTAL IMPACT S
DEIS = DRAFT
FEIS = FINAL

PSD PREVENTION OF SIGNIFICA

404 SECTION 404 OF THE CLEA
DREDGING OR FILLING IN

NPDES NATIONAL POLLUTANT DIS

TING SCHEDULE / CROW SYNFUELS PROJECT



IN PREPERATION OF EIS

INDIAN AFFAIRS

TAL IMPACT STATEMENT
= DRAFT
= FINAL

OF SIGNIFICANT DETERIORATION (OF AIR QUALITY)

OF THE CLEAN WATER ACT GOVERNING FILLING IN THE WATERS OF THE U.S.

LLUTANT DISCHARGE ELIMINATION

ABOUT THE CHART

1. THIS IS NOT A COMPREHENSIVE LIST OF PERMITS AND APPROVALS WHICH MAY BE REQUIRED FOR THE SYNFUELS PROJECT.

2. THE PROCEDURES AND TIMING ARE BASED ON CURRENT STATUTES, REGULATIONS, POLICY, AND PRACTICE.

4.5 RESIDUAL QUANTIFICATION

The major environmental residuals derived from the environmental analysis conducted for this feasibility study are identified and quantified on an annual basis in the subsequent discussion. Since a zero discharge concept was applied to all wastewater residuals associated with the operation of the proposed coal gasification facility, major emphasis was placed on the quantification of gaseous and particulate emissions to the ambient atmosphere and the solids and/or solid-liquid mixtures resulting principally from the flue gas desulfurization (FGD) system within the power plant boiler operation and the ash residual from both the boiler operation and the overall Lurgi gasification process.

4.5.1 Residuals From Air Emissions

Preliminary annual estimates of major air pollutants emitted to the ambient atmosphere past the postulated emission control systems are presented in Table 4.5.1-1 for two preliminary sets of gasification plant design case scenarios based upon 275 MM SCF/D (250 MM SCF/CD) SNG production utilizing the Westmoreland and Shell coal supplies.

The bases used in the determination by Fluor of the major gaseous emissions to the ambient atmosphere are presented as follows:

(1) Westmoreland and Shell coal analyses used as determined by Lurgi for the gasification balance: sulfur is 0.82 weight percent, ash is 7.4 weight percent, and HHV is 8,612.3 Btu/lb (as-received basis) for the Westmoreland coal sample. Sulfur is 0.38 weight percent, ash is 4.1 weight percent, and HHV is 9,090.1 Btu/lb (as-received basis) for the Shell coal sample.

TABLE 4.5.1-1

AIR RESIDUALS: GASEOUS EMISSIONS

Constituent	WESTMORELAND COAL Case I tons/year	WESTMORELAND COAL Case II tons/year	SHELL COAL Case II tons/year
H_2S	16	16	8
COS	-	-	-
CH_4	262	262	342
C_2H_6 C_3H_8	80	80	64
O_2	869,500	2,307,600	2,414,700
N_2	12,680,400	33,157,300	34,157,000
H_2O	2,054,500	5,229,200	5,354,900
NO_2	8,610	22,400	23,100
SO_2	4,250	9,510	6,430
CO_2	10,471,700	16,422,200	16,484,500
CO	1,560	3,160	3,320

(2) Two boiler capacities are evaluated:

Case I: Plant generates sufficient power for all internal needs and neither exports or imports power.

Case II: Plant generates power in excess of internal needs assuming 40 weight percent coal fines are fed to the boiler.

(3) Coal feed to the plant is as follows:

Westmoreland Coal		Shell Coal	
To Gasifiers	To Boilers	To Gasifiers	To Boilers
Case I - 21,600 t/d	4,800 t/d	—	—
Case II - 21,600 t/d	14,500 t/d	21,120 t/d	14,080 t/d

(4) Emission calculations are based on the following:

Boiler flue gas: 90 weight percent of sulfur in coal feed (Westmoreland coal) to boilers is recovered, and 10 weight percent exists as SO_2 in the flue gas. Shell coal sulfur removal efficiency is 84 weight percent. NO_x emission rate is 0.5 lb/10^6 Btu HHV coal feed to boilers (calculated as NO_2). Particulated emissions are based on an FGD exit concentration of 0.013 grains/scf (overall particulate removal efficiency is 99.7 percent for Westmoreland coal and 99.4 percent for Shell coal). Electrostatic precipitators and flue gas desulfurization are used to control particulate and sulfur dioxide emissions from the coal-fired boilers.

Vent Gas Incineration: Claus unit followed by a SCOT tail gas treating unit and a Stretford unit treat the process gas prior to incineration. The Claus unit removes 93 percent of the sulfur in its feed. The Stretford unit removes 99.9 percent of H_2S in its feed. Incinerator vent gas contains approximately 1.4 weight percent of the sulfur in the feed to process (1.5 weight percent in the Shell case).

Gasification Lock Gas Vent: 2.0 weight percent of lock gas is vented. Composition is that recommended by Lurgi.

Gasification startup: Confidential Lurgi information.

Coal Screening/Distribution: Fluor in-house experience.

Tank Farm: Hydrocarbon emissions from storage tanks are based on floating roof design with secondary seals. Vapor recovery systems are utilized on cone roof storage.

Fired Heater Flue Gas: NO_x @ 0.5 lb $NO_2/10^6$ Btu-fired HC and particulates are negligible; fuel gas contains no sulfur.

Tar Distillation Heater: Westmoreland coal, 24.4 MM Btu/hr; Shell coal, 40.6 MM Btu/hr.

Methanation: Catalyst reduction requires fuel gas. Maximum NO_x emission rate is 43 lb/hr.

Flares: NO_x emissions are 0.5 lb/10^6 Btu of fuel gas burned.

Wastewater Treating Incinerator: NO_x emissions are 0.5 lb/10^6 Btu of fuel gas burned.

(5) Fugitive hydrocarbon emissions throughout the plant are not included.

Quantification of estimates for stack emissions of trace elements in the form of particulate matter are based upon utilization of an electrostatic precipitator (ESP) as the best available control technology (BACT), assuming an overall removal efficiency of 99.7 percent as previously cited. The additional assumption for the boiler ash distribution in this analysis was 80 percent fly ash and 20 percent bottom ash. The preliminary annual estimates for 26 trace elements released as particulates to the ambient atmosphere are presented in Table 4.5.1-2 for the Cases I and II design scenarios utilizing the Westmoreland coal feed and for the Case II design scenario employing Shell coal.

Initial concentrations of the trace elements in the Westmoreland and Shell raw coal feeds are based upon chemical analyses of representative case drill hole samples as presented in Table 4.5.1-3. The analysis was affected by the CERT AERMOD computer program which utilizes experimentally derived trace element penetration data for electrostatic precipitators developed for workers at Lawrence Livermore Laboratory (EST, Volume 13, 1979). (References 48,81).

4.5.2 Residuals From Solids

Preliminary annual estimates of the major solids residuals, consisting primarily of the ash from the Lurgi coal gasification units, bottom ash from the boilers, and sludge from the flue gas desulfurization (FGD) unit, were derived for a plant production rate of 250 MM SCF/D SNG. Representative gasifier and boiler ash characteristics are based upon Lurgi analysis of the gasifier ash resulting from test samples of both the Westmoreland and Shell coals as presented in Table 4.5.2-1. The FGD sludge composition shown in Table 4.5.2-2 is based on estimates from the selected vendor, Davy McKee, for the FGD system for purposes of this feasibility study as discussed in more detail in Volume II of this report.

Annual solids residuals inventories for both Case I and Case II design scenarios employing a Westmoreland coal feed and a Case II design utilizing Shell coal are presented in Table 4.5.2-3 on a dry weight basis. The tonnages were also based upon 7.4 weight percent ash and 4.1 weight percent ash, respectively, for the Westmoreland and Shell coals as determined by Lurgi for the plant gasification balance. Electrostatic precipitator removal efficiencies of 99.7 percent and 99.4 percent, respectively, were assumed for Westmoreland and Shell design scenarios for

TABLE 4.5.1-2

PRELIMINARY ANNUAL ESTIMATES OF TRACE ELEMENT PARTICULATE AIR EMISSIONS 250 MM SCF/D CROW COAL GASIFICATION PLANT CASE I AND II DESIGN SCENARIOS: WESTMORELAND AND SHELL COAL SUPPLIES

	Westmoreland Coal		Shell Coal
Element	Case I lb/yr (tons/yr)	Case II lb/yr (tons/yr)	Case II lb/yr (tons/yr)
Arsenic	299 (0.15)	575 (0.29)	1,991 (1.00)
Barium	10,663 (5.33)	20,528 (10.26)	19,332 (9.67)
Beryllium	17 (1.01)	32 (0.02)	10 (0.005)
Bromine	40 (0.02)	77 (0.04)	8(0.004)
Cadmium	233 (0.12)	448 (0.22)	181 (0.09)
Cerium	334 (0.17)	643 (0.32)	246 (0.12)
Cobalt	133 (0.07)	256 (0.13)	107 (0.05)
Chromium	355 (0.18)	683 (0.34)	796 (0.40)
Cesium	10 (0.005)	18 (0.01)	7 (0.003)
Gadolinium	23 (0.01)	44 (0.02)	76 (0.04)
Lanthanum	105 (0.05)	201 (0.10)	62 (0.08)
Molybdenum	365 (0.18)	702 (0.35)	1,176 (0.59)
Manganese	4,744 (2.37)	9,134 (4.57)	1,777 (0.89)
Lead	266 (0.13)	513 (0.26)	558 (0.28)
Rubidium	97 (0.05)	186 (0.09)	370 (0.19)
Antimony	76 (0.04)	146 (0.07)	288 (0.14)
Scandium	48 (0.02)	92 (0.05)	313 (0.16)
Selenium	147 (0.07)	283 (0.14)	217 (0.11)
Strontium	14,591 (7.30)	28,092 (14.05)	18,310 (9.16)
Tantalum	15 (0.008)	30 (0.08)	29 (0.01)
Thorium	70 (0.04)	135 (0.07)	92 (0.05)
Uranium	32 (0.02)	61 (0.03)	119 (0.06)
Vanadium	1,004 (0.50)	1,932 (0.97)	2,376 (1.19)
Tungsten	66 (0.03)	127 (0.06)	289 (0.15)
Zinc	1,659 (0.83)	3,195 (1.60)	3,814 (1.91)
Zirconium	11,837 (5.92)	22,789 (11.40)	16,525 (8.21)

TABLE 4.5.1-3
TRACE ELEMENT ANALYSIS FOR WESTMORELAND AND SHELL COALS

Trace Element	Westmoreland Average Concentration (ppm)	Shell Average Concentration (ppm)
Antimony	0.67	0.59
Arsenic*	1.77	3.19
Barium*	181.60	89.05
Beryllium*	1.25	0.21
Boron	218.60	44.09
Bromine	19.35	1.08
Cadmium*	1.80	0.38
Cerium	17.64	3.52
Chromium*	6.36	3.86
Cobalt	3.62	0.79
Copper*	21.42	11.57
Fluorine	227.40	95.29
Lead*	3.30	1.87
Lithium	35.20	8.89
Manganese	202.00	20.46
Mercury*	0.08	0.08
Nickel*	7.22	2.19
Selenium*	1.30	0.52
Silver*	0.09	0.14
Strontium	497.02	168.69
Thallium	0.23	0.36
Uranium	1.43	1.45
Vanadium	18.48	11.83
Zinc*	15.70	9.76
Zirconium	128.00	48.04

*Classified by EPA as hazardous (toxic)

Source: Westmoreland Final EIS (1975), Table 14, R-1 average.
Shell Mining Company (1982), Private Communication.

TABLE 4.5.2-1

GASIFIER AND BOILER ASH CHARACTERISTICS

Component	Shell Weight Percent	Westmoreland Weight Percent
Phosphoris Pentoxide (P_2O_5)	0.3	0.28
Silica (SiO_2)	29.4	35.9
Ferric Oxide (Fe_2O_3)	6.2	7.5
Alumina (Al_2O_3)	16.1	19.2
Titania (TiO_2)	1.6	1.2
Lime (CaO)	21.3	14.5
Magnesia (MgO)	7.3	2.4
Sulfur Trioxide (SO_3)	13.9	14.1
Potassium Oxide (K_2O)	0.36	0.18
Sodium Oxide (Na_2O)	0.35	3.0
Carbon (C)	4.5	4.0
Undetermined	0.6	1.74

TABLE 4.5.2-2
FLUE GAS DESULFURIZATION
SLUDGE COMPOSITION

	Percent
$CaSO_4 \cdot 2\ H_20$	75.0
$CaCl_2$	0.5
$Ca\ (OH)_2$	Trace
$Ca\ (C00H)_2$	Trace
Lime Inerts	1.5
H_20	23.0
Total	100.0

TABLE 4.5.2-3
CROW COAL GASIFICATION PLANT, 250 MM SCF/D SNG PRODUCTION
MAJOR SOLIDS RESIDUALS PRELIMINARY ANNUAL ESTIMATES

	WESTMORELAND COAL		SHELL COAL
CONSTITUENT	CASE I tons/yr	Case II tons/yr	Case II tons/yr
Boiler ash	115,878	281,84	190,475
Gasifier ash	549,386	549,242	297,445
FGD Sludge	65,952	197,861	84,357
Totals	731,216	1,028,987	572,227

the boiler fly ash. Additionally, SO_2 emission control efficiencies of 90 percent and 84 percent, respectively, were assumed for the boiler FGD units for the Westmoreland and Shell coal supplies. All design scenarios for both coal feeds assumed a 20 percent retention of the sulfur in the boiler bottom ash residue and a 332-day operating year.

4.6 ENVIRONMENTAL IMPACTS ASSESSMENT

4.6.1 Air Quality Impacts Assessment

The major environmental regulatory constraint imposed by the proposed Crow coal gasification project at this time entails compliance with the Class I air quality designation for the adjacent Northern Cheyenne Reservation. Therefore, a two-phase air quality dispersion modeling analysis was conducted during the course of this study to evaluate candidate plant sites and to ascertain the SO_2 and particulate matter control requirements necessary to meet the Class I air quality PSD increment for these two potential pollutants.

A selection process to obtain a Best Available Control Technology (BACT) to meet the Class I PSD requirements derived from the modeling analysis was then affected. Hence, the evaluation of the proposed major air emission control devices (i.e., the flue gas desulfurization (FGD) unit to control the boiler plant air emissions and the SCOT, ADIP, Claus, and Stretford units to limit air emissions within the Lurgi gasification process) is discussed to demonstrate the viability of those intended mitigation measures to preclude potential adverse air quality environmental impacts at two selected candidate plant sites.

4.6.1.1 Preliminary Air Quality Screening Analysis

A two-stage air quality screening analysis was conducted to determine potential air quality environmental impacts due to air pollutant emissions emanating from a 250 MM SCF/D high-Btu SNG coal gasification facility located on the Crow Reservation. The first stage of the analysis entailed an early preliminary screening of eight possible plant candidate siting areas. Primary emphasis in the first stage was placed upon a preliminary evaluation of the potential environmental air quality impacts with respect to compliance with the Prevention of Significant Deterioration (PSD) increment standards to the nearby Class I air quality-designated area of the Northern Cheyenne Reservation, since the stringency of these standards could impose serious plant design and siting constraints upon the proposed project. Thus, the early preliminary air quality screening analysis became a major driver in the site selection process discussed in greater detail under Special Studies in Volume V of this report.

The second phase of the screening analysis centered on a more detailed evaluation of emission control requirements and ancillary plant design features for the more promising candidate siting areas on the basis of the results of the siting evaluation and the evolution of the final plant process design data discussed in greater detail in Volume II.

All air quality screening analysis determinations were performed primarily with the EPA VALLEY Model, utilizing the rural, short-term (24-hour), complex terrain option of the program. This was recommended by the EPA OAQPS Guideline on Air Quality Models (EPA 1980) in screening evaluations for regions exhibiting irregular terrain features and where detailed, site-specific surface and upper atmospheric data are not available. As further recommended in the OAQPS guide, worst-case meteorological conditions of 2.5 m/s surface wind speed and a Pasquill-Gifford F-stability (moderately stable) wind category were utilized in all model runs for these analyses. (References 11, 12, 70).

Terrain maps for each site were derived for each candidate site scenario to establish the three-dimensional source-receptor geometric relationships. Thus, the computer model consists of a "tertiary" coupling of pertinent plant design parameters, surface and upper winds meteorological data and the three-dimensional source-receptor geometries. The plume dispersion and transport is then simulated mathematically in the VALLEY model by means of equations derived from a bivariate Gaussian expression.

Early Preliminary Air Quality Screening Analysis: Plant Siting Evaluation. Eight representative candidate site locations as shown in Figure 4.6.1-1 were selected for the preliminary air quality screening evaluations. Sites 1, 1A, 6, and 7 were potential site locations previously evaluated by CERT for the Crow Power Plant

Feasibility Study. Sites 8 (located near the town of Lodge Grass), 20, 22, and 23 were also selected as possible candidate sites within the ongoing Crow Synfuels Feasibility Study.

Two candidate sites, 20 and 23, are located in the southeastern part of the Crow Reservation. Site 20 is located northwest of the Aberdeen Strip and south of Wyola. Site 23 is located north of Tanner Creek adjacent to the Shell coal mining lease area, thus representing a potential "minemouth" siting opportunity. Site 22, located in the northeastern part of the Crow Reservation near the Westmoreland coal mining operation, also represents a potential "minemouth" siting location. Terrain maps for each site were derived for inclusion in the VALLEY model and are summarized for each of the eight plant candidate site scenarios in Table 4.6.1-1.

Two preliminary plant design case scenarios were developed by Fluor Engineers and Constructors, Inc., based upon the preliminary average coal analysis data for the two potential coal suppliers, Westmoreland and Shell, as shown in Tables 4.6.1-2 and 4.6.1-3 respectively.

The Case I plant design assumes a plant production of 250 MM SCF/D SNG and generation of sufficient power for internal requirements only. The Case II plant design also assumes a 250 MM SCF/D SNG production capability but assumes that 40 percent fines in the coal feed are supplied to the boilers to produce approximately 270 MW of electrical power for sales.

The preliminary plant emission data utilized in the air quality screening analysis model for the two design cases is presented in Table 4.6.1-4 for an assumed Westmoreland coal feed and in Table 4.6.1-5 for an assumed Shell coal feed.

Perusal of the low emission rates for particulates, based upon 98 percent emission control efficiencies, for Case I and II designs presented in Table 4.6.1-4 and 4.6.1-5 and the Class I PSD air quality maximum allowable increments as shown in Table 4.6.1-6, indicates that potential SO_2 emissions represent the salient constraint for this analysis of candidate sites in terms of satisfying Class I PSD air quality

FIGURE 4.6.1-1

PRELIMINARY AIR QUALITY SCREENING ANALYSIS:

TENTATIVE SITING LOCATIONS

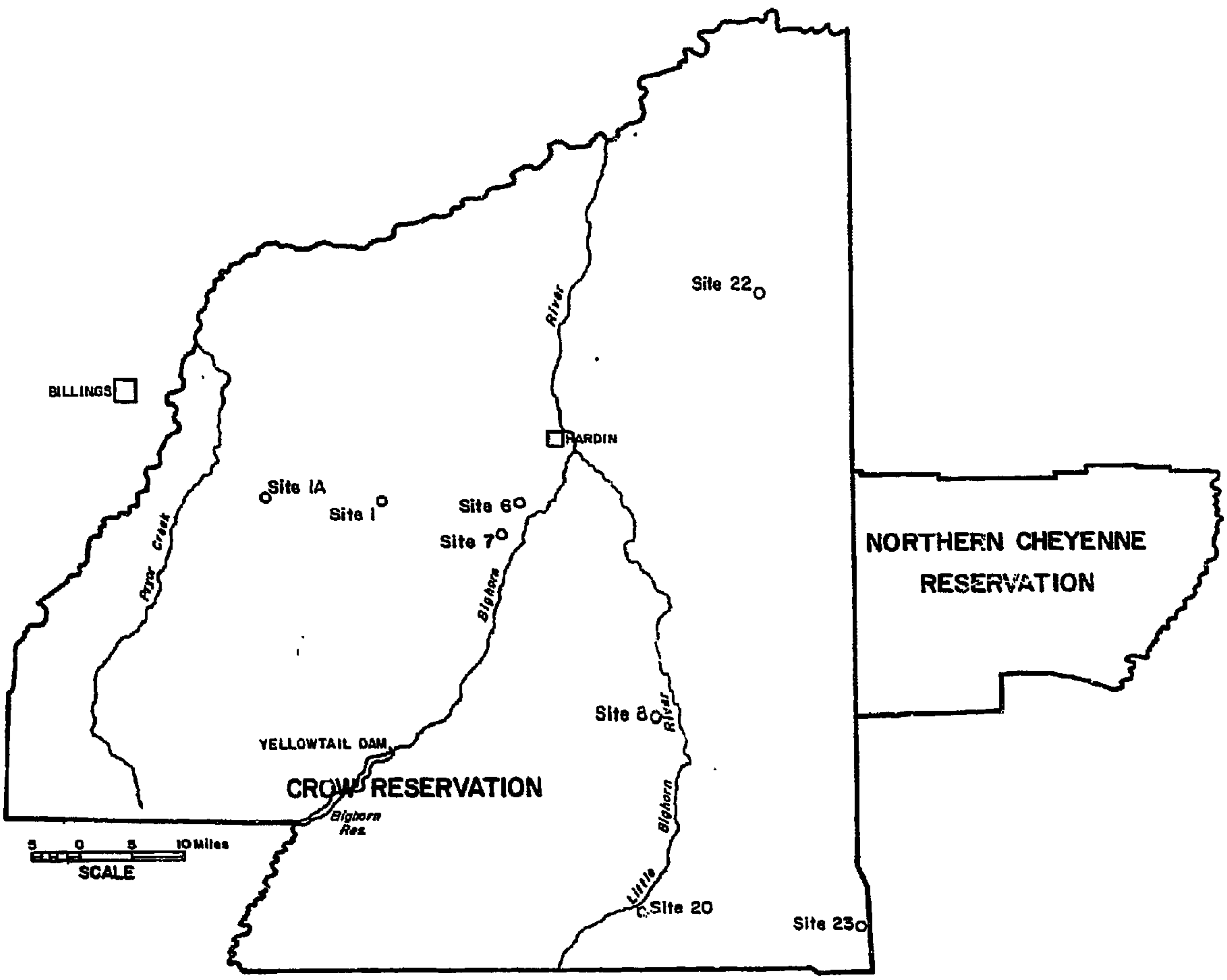


TABLE 4.6.1-1

CRCV SYNFUELS FEASIBILITY STUDY: TERRAIN CONSIDERATIONS, VALLEY DISPERSION MODELING ANALYSIS, CANDIDATE SITING EVALUATION

Cardinal Compass Point Direction	Radial Distance from Plant Site Origin (Miles)					
SITE 1 (Base Elev.: 3440 ft msl):	12	24	36	48	60	72
ENE	3050	3100	3315	3440	3350	—
E	3000	3450	3550	3750[a]	4000[a]	4300[a]
ESE	3100	3300	3400	3800[a]	4350[a]	3500[a]
	5	10	15	20	25	30
W	3440	3680	3470	3600	3760	3640
WNW	3470	3650	3840	3330	3210	3280
SITE 6 (Base Elev.: 3100 ft msl):	10	20	30	40	50	60
E	3000	3500	3900[a]	3750[a]	4000[a]	4350[a]
ESE	3060	3400	3650	3800[a]	3850[a]	3200
SE	3200	3250	4000	4900[a]	4000[a]	—
W	3400	3500	3900	3700	3400	—
WNW	3500	3550	3600	3300	4000	—
SITE 7 (Base Elev.: 3100 ft msl):	11	22	33	44	55	66
ENE	3300	3350	3800	4820	3300	3100
E	3000	3630	3800[a]	3800[a]	4000[a]	3950[a]
ESE	3400	3450	3815[a]	4500[a]	3500	3350
W	3500	3760	3900	3900	—	—
WNW	3460	4000	3900	3500	—	—
SITE 1A (Base Elev.: 3450 ft msl):	24	36	48	60	72	84
ENE	3300	3315	3440	3350	3350	3600
E	3250	8450	3550	3800[a]	3480[a]	4300
ESE	3100	3450	3500	4200[a]	4430[a]	4200[a]

TABLE 4.6.1-1
(continued)

Cardinal Compass Point Direction	Radial Distance from Plant Site Origin (Miles)					
SITE 8						
(Base Elev.: 3500 ft msl):	6	12	18	24	30	36
NE	3450	3550	3600	3750[a]	3750[a]	3900[a]
ENE	3650	3650	4340[a]	4350[a]	4100[a]	3950[a]
E	3650	3655	4340[a]	4300[a]	4250[a]	4110
SITE 20						
(Base Elev.: 4000 ft msl)	10	20	30	40	50	60
NE	3850	3850	3855[a]	4400[a]	3950[a]	3600[a]
ENE	3860	3965	3800	3875[a]	3300[a]	3850
SITE 22						
(Base Elev.: 3360 ft msl)	6	12	18	24	30	36
ESE	3360	3370	3365	3370	3375	3900[a]
SE	3365	3385	3365	3600[a]	3300[a]	4150[a]
SSE	3360	3365	3600[a]	3750[a]	3550[a]	3700[a]
SITE 23						
(Base Elev.: 4100 ft msl)	10	20	30	40	50	60
N	4380	4400[a]	4380[a]	4390	4385	4380
NNE	4380	4450[a]	4400[a]	4375	4370	4375
NE	4385	4375	4380[a]	4380[a]	4400	4385

[a]Receptors located within or near the Northern Cheyenne Reservation.

Note: 1. Receptor elevations in units of ft msl.
2. Nearest distance to reservation boundary: Site 1, 44.2 miles (71.1 km); Site 6, 33.2 miles (53.4 km); Site 7, 34.1 mi. (54.7 km). Site 1A, 56.2 mi. (90.4 km). Site 8, 18.5 mi. (29.8 km). Site 20, 27.7 mi. (44.6 km). Site 22, 17.5 mi. (28.2 km). Site 23, 20.2 mi. (32.5 km).

TABLE 4.6.1-2
WESTMORELAND COAL ANALYSIS DATA

	Average	Low	High
Btu/lb.	8646	8389	9029
Equilibrim	23.34	21.49	24.72
Grindability Index Hardgrove)	50.0	44.4	58.8
Proximate Analysis, %			
Moisture	23.50	20.25	25.57
Volatile Matter	29.75	26.15	32.59
Fixed Carbon	36.52	34.29	39.20
Ash	10.23	8.65	11.73
	100.00		
Ultimate, %			
Carbon, C	50.65	49.18	52.94
Hydrogen, H_2	3.42	3.09	3.62
Sulfur, S	.72	.60	.89
Oxygen, O_2	10.73	9.76	12.42
Nitrogen, N_2	.74	.49	1.16
Moisture	23.50	20.25	25.57
Ash	10.23	8.65	11.73
Chlorine	.01	.00	.02
	100.00		
Sulfur Forms As Rec'd., %			
% Pyritic Sulfur	.33	.19	.50
% Sulfate Sulfur	.01	.00	.02
% Organic Sulfur	.38	.26	.57
	.72		
Phos. Pentoxide, P_2O_5	.41	.18	1.70
Silica, SiO_2	38.71	35.41	44.02
Ferric Oxide, Fe_2O_3	6.21	4.18	8.25
Alumina, Al_2O_3	18.04	16.19	21.27
Titania, TiO_2	.68	.38	1.36
Lime, CaO	14.93	12.64	17.33
Magnesia, MgO	2.90	1.21	4.43
Sulfur Trioxide, SO_3	13.67	10.48	16.50
Potassium Oxide, K_2O	1.04	.42	1.46
Sodium Oxide, Na_2O	2.42	.46	3.67
Undetermined	.99	.00	2.31
	100.00		

TABLE 4.6.1-3
SHELL COAL ANALYSIS DATA SHELL COAL ANALYSIS
(YOUNGS CREEK AS RECEIVED)

	Average Values	Expected Critical Design Limit
Proximate Analysis		
Moisture	24.95%	29.9 lb/MM Btu
Volatile	33.02%	40.6 lb/MM Btu
Ash	5.02%	9.3 lb/MM Btu
Fixed Carbon (% of coal):	36.83%	
Sulfur	0.31%	0.5 lb/MM Btu
Thermal Energy (Btu/lb):	9063	8850
Weighted Average: Diluted as received		
Ultimate Analysis		
Carbon:	52.34%	
Hydrogen	3.68%	
Chlorine:	0.01%	
Oxygen:	12.39%	
Nitrogen:	0.79%	1.1 lb/MM Btu
Mineral Analysis of Ash (% of coal)		
Phosphorous Pentoxide: P_2O_5	0.74	
Silica: SiO_2	27.71	
Ferric Oxide: Fe_2O_3	4.61	
Alumina: Al_2O_3	15.89	
Lime: CaO	22.47	
Magnesia: MgO	7.50	
Sulfur Trioxide: SO_3	15.44	
Potassium Oxide: K_2O	0.59	
Sodium Oxide: Na_2O	2.84	5.1
Titanium Oxide: TiO_2	1.12	
Undetermined:	1.06	
Definition: Undiluted weighted average		
Hardgrove Grindability:	45.47	40
Equilibrum Moisture (% of coal)	23.84	

TABLE 4.6.1-3
(continued)

	Average Values	Expected Critical Design Limit
Fusion Temperature of Ash (°F) -oxidizing atmosphere		
Initial deformation:	2320	2224
Spherical softening (H=W):	2354	2266
Hemispherical softening (H=1/2W)	2371	2283
Fluidization:	2398	2308
Sulfur Forms (% of coal)		
Pyrite:	0.07	
Sulfate	0.01	
Organic	0.23	

TABLE 4.6.1-4
PRELIMINARY PLANT EMISSIONS DATA: WESTMORELAND COAL FEED

Boiler Emission Summary

Component	Case I Uncontrolled	Case I Controlled	Case II Uncontrolled	Case II Controlled
Particulates, T/yr.	230,600	730	386,500	1,230
NOx, T/yr.	(1)	12,180	(1)	20,420
SO_2, T/yr.	40,580	4,060(2)	68,010	6,800(2)

(1) As NO_2, special burner required to achieve emission level.

(2) 90 weight percent SO_2 removal; EPA requires 70 weight percent SO_2 removal. Controlled emissions meeting EPA standards are 12,170 T/D Case I and 20,400 T/D Case II.

Stack Information

Component	Case I	Case II
Stack Height	250 ft.	250 ft.
Stack Diameter	35 ft.	46 ft.
Exit Gas Velocity	36 ft./sec.	35 ft./sec.
Volumetric Flow Rate	2.1MM ACFM	3.5MM ACFM
Exit Gas Temperature	375 °F	375°F

Process Off-Gas Incinerator Emission Summary

Component	Case I Uncontrolled	Case II Controlled
Particulates	N/A	N/A (1)
SO_2, T/yr.	102,100	4,320
NOx, T/yr.	-	2,630

TABLE 4.6.1-4
(continued)

Stack Information

Component	Case I/II
Stack Height	150 ft.
Stack Diameter	25 ft.
Exit Gas Velocity	35 ft./sec.
Volumetric Flow Rate	1.1 MM ACFM
Exit Gas Temperature	500^{o}F

(1) Gas-fired, no emissicn controls required.

(2) As NO_2, special burner required to achieve emission level.

TABLE 4.6.1-5
PRELIMINARY PLANT EMISSIONS DATA:
SHELL COAL FEED

Boiler Emission Summary

Component	Case I Uncontrolled	Case I Controlled	Case II Uncontrolled	Case II Controlled
Particulates, T/yr.	11,800	730	187,400	1,230
NOx, T/yr.	(1)	12,170	(1)	20,410
SO_2, T/yr.	16,660	5,000(2)	27,930	8,380(2)

(1) As NO_2, special burner required to achieve emission level.

(2) 90 weight percent SO_2 removal.

Stack Information

Component	Case I	Case II
Stack Height	250 ft.	250 ft.
Stack Diameter	36 ft.	46 ft.
Exit Gas Velocity	35 ft./sec.	35 ft./sec.
Volumetric Flow Rate	2.1MM ACFM	3.5MM ACFM
Exit Gas Temperature	375 °F	375°F

Process Off-Gas Incinerator Emission Summary

Component	Case I Uncontrolled	Case II Controlled
Particulates	N/A	N/A (1)
SO_2, T/yr.	102,100	4,320
NOx, T/yr.	-	2,630

TABLE 4.6.1-5
(continued)

Stack Information

Component	Case I/II
Stack Height	150 ft.
Stack Diameter	25 ft.
Exit Gas Velocity	35 ft./sec.
Volumetric Flow Rate	1.1 MM ACFM
Exit Gas Temperature	500°F

(1) Gas fired, no emission controls required.

(2) As NO_2, special burner required to achieve emission level.

TABLE 4.6.1-6
PREVENTION OF SIGNIFICANT DETERIORATION OF AIR QUALITY STANDARDS[a]

		Maximum Allowable Increase, ug/m^3		
Pollutant	Averaging Time	Class I	Class II	Class III
Particulate matter	Annual	5	10	37
	24-hour			
SO_2	Annual	2	20	40
	24-hour	5	91	182
	3-hour	25	512	700

[a]40 CFR 52.21 and 42 USC 7401 et seq. Section 163.

NOTES:

1. Variances to the Class I increments are allowed under certain conditions as specified at Section 165 (d)(c)(ii) and (iii) and at 165 (d)(D)(i) of the Clean Air Act of 1977.

2. EPA was to have promulgated similar increments for HC, CO, ozone, and NO_x by August 7, 1979; they are under development. Increments for Pb were due to be promulgated by October 5, 1980.

standards within the adjacent Northern Cheyenne Reservation. Therefore, the early preliminary screening analysis centered on an evaluation of the candidate plant site scenarios for compliance with the 24-hour Class I PSD air quality standards for SO_2 emissions. The results of the screening analysis for the eight plant candidate sites are summarized in Table 4.6.1-7.

Downwind receptor pollutant concentrations in air dispersion modeling analysis with complex terrain physiography are intricate interrelationships between the source and receptor in terms of source emission rates, plume diffusional properties, and the geometric variations in elevation, direction, and distance. This assumes, in this preliminary screening analysis, that the same meteorological conditions exist for each case.

Site 23 is shown in Table 4.6.1-7 to be the most favorable candidate site location in terms of compliance with 24-hour Class I PSD standards. Compliance can be achieved with baseline or minimum 70 percent SO_2 control efficiency on the boiler and minimum 62 percent SO_2 control efficiency on the vent gas incinerator assuming both plant physical stack heights at 250 feet for the Case I design scenario and the more stringent Case II design scenario based upon the use of Shell coal. The desirability of this site is primarily due to the plant base elevation of 4,100 feet MSL resulting in decreased source-receptor elevation differences at the most significant receptor locations within the Northern Cheyenne Reservation. This factor, coupled with adequate source-receptor separation distances for the assumed worst-case meteorological conditions, results in an increase in effective stack height which, in turn, enhances plume dispersion. Hence, ground-level receptor SO_2 concentrations are reduced significantly for this plant site scenario.

Site 20 is also shown to comply for the baseline case of 90 percent SO_2 emission control efficiency for the boiler and 96 percent SO_2 emission control efficiency for the vent gas incinerator with a Westmoreland coal feed, assuming a physical stack height of 250 feet for both effluent streams. However, the use of the Shell coal requires an increase in stack heights for both the boiler and vent gas incinerator effluents to 500 feet to sufficiently increase the effective stack (physical stack

Tí Ê 4.6.1-7

PRELIMINARY SCREENING ANALYSIS SUMMARY: PLANT SO_2 CONTROL EFFICIENCIES AND PHYSICAL STACK HEIGHT REQUIREMENTS FOR 24-HOUR CLASS I PSD COMPLIANCE, CROW SYNFUELS PRELIMINARY SITING EVALUATION

Site ID	Assumed Plant Base Elevation, ft. MSL	Coal Feed	CASE I Boiler SO_2 Control Efficiency, %	CASE I Incinerator SO_2, Control Efficiency, %	CASE II Boiler SO_2 Control Efficiency, %	CASE II Incinerator SO_2, Control Efficiency, %
1	3440	Westmoreland	90[e,f]	98[e,f]	90[d,e,f]	98[d,e,f]
		Shell	90[c,e]	95[c,e]	90[c,e]	95[c,e,]
1A	3500	Westmoreland	90[a,c]	98[c,e]	90[a,c,d]	98[c,d,e]
		Shell	85[c,d]	90[c,d]	85[c,d]	90[c,d]
6	3000	Westmoreland	95[c,d,e]	98[c,d,e]	NC	NC
		Shell	90[c,e]	95[c,e]	NC	NC
7	3100	Westmoreland	95[c,d,e]	98[c,d,e]	NC	NC
		Shell	90[c,d,e]	95[c,d,e]	NC	NC
8	3500	Westmoreland	NC	NC	NC	NC
		Shell	NC	NC	NC	NC
20	4000	Westmoreland	90[a,b]	96[a,b]	90[a,b]	96[a,b]
		Shell	70[a,c]	62[a,c]	70[a,c]	62[a,c]
22	3360	Westmoreland	NC	NC	NC	NC
		Shell	-	-	-	-
23	4100	Westmoreland	-	-	-	-
		Shell	70[a,b]	62[a,b]	70[a,b]	62[a,b]

CASE I - 250 MM SCFD SNG Plant Only
CASE II - 250 MM SCFD SNG Plant Plus 270 MW Deliverable Electric Power

a-Base case SO_x emission control efficiencies
b-incinerator stack height raised to 250 ft.
c-both stack heights raised to 500 ft. (assumed upper limit)
d-Marginal compliance-preliminary results _ 10% greater than 24 hour, Class I PSD standard
e-assumed upper limit for SO_2 emission control efficiency
f-both stack heights raised to 625 ft.
NC-case results do not comply with Class I PSD standard with assumed upper limits for SO_2 emission control efficiencies and physical stack height.

height plus plume buoyancy) with respect to the most significant source-receptor directions, elevations, and distance intervals for this scenario. As in the Site 23 scenario, baseline or minimum SO_2 control efficiencies for both the boiler plant and vent gas incinerator of 70 percent and 62 percent, respectively, were adapted for the Site 20 evaluation utilizing the Shell coal feed.

Site 1A is shown in Table 4.6.1-7 to comply marginally, i.e., less than or equal to 10 percent greater than the 24-hour Class I PSD increment for SO_2, using the aforementioned baseline SO_2 emission control efficiency for the boiler emissions and a 98 percent SO_2 emission control efficiency for the vent gas incinerator utilizing Westmoreland coal and assuming a physical stack height of 500 feet for both effluent streams. Similarly, use of the Shell coal feed results in marginal compliance with 24-hour Class I PSD standards and reduced SO_2 emission control efficiencies for boiler and vent gas incinerator emissions of 85 percent and 90 percent, respectively, as evidenced in Table 4.6.1-7.

Site 1 is shown in Table 4.6.1-7 to require a physical stack height of 625 feet to comply marginally with the 24-hour Class I PSD increment for SO_2 with Westmoreland coal. This assumes the baseline (90 percent) SO_2 emission control efficiency for boiler emissions and 98 percent SO_2 emission control efficiency for the vent gas incinerator.

Sites 6 and 7 are shown in Table 4.6.1-7 to be in noncompliance with the 24-hour SO_2 Class I PSD standard for the Case II design scenario with either coal supply. This is primarily due to the combinatory effects of relatively low plant base elevations with respect to the elevations at pertinent receptor locations and the proximity of the two candidate plant sites to the boundaries of the Northern Cheyenne Reservation as shown in Table 4.6.1-1. However, candidate Sites 6 and 7 are shown to be in Class I PSD compliance marginally for the Case I design scenario with both the Westmoreland and Shell coals being utilized as feedstock for the gasification plant. The above marginal compliance is predicated on a 95 percent SO_2 emission control efficiency for the boiler emissions, a 98 percent SO_2 emission control efficiency for the vent gas incinerator emissions utilizing the Westmoreland coal supply, and 90 percent and 95 percent, respectively, for boiler and vent gas incinerator SO_2 emission control efficiencies employing the Shell coal.

Site 8 is shown to be in noncompliance with the 24-hour SO_2 Class I PSD standard for either design case or coal supply, primarily due to the close proximity of the plant to the Northern Cheyenne Reservation (18.5-mile distance to nearest reservation boundary as shown in Table 4.6.1-1 and the source-receptor elevation differences as shown in Table 4.6.1-1).

Substantially for similar reasons, Site 22, the minemouth siting opportunity near Westmoreland's Absaloka mine, fails to comply with the 24-hour SO_2 Class I PSD standard. The relatively low plant base elevation (3,360 feet msl), with respect to the source-receptor elevation differences (Table 4.6.1-1), and the close proximity to the nearest boundaries of the Northern Cheyenne Reservation (17.5 miles) are the major contributory factors for noncompliance at candidate Site 22.

Summarily, the early preliminary air quality screening analysis of eight candidate plant sites resulted in the elimination of four candidate sites from further consideration within the framework of this feasibility study due to failure to comply with the major constraint imposed by the Class I air quality designation on the adjacent Northern Cheyenne Reservation. Two of the remaining four candidate sites, Sites 1 and 23, were selected during the course of the overall siting evaluation (discussed in considerable detail in Volume V) for additional sensitivity analyses utilizing the refinements to the emissions data derived from the coal gasification process and plant design effort. The gasification process and plant design were based upon the results of the Lurgi test data for acceptable gasification properties of representative coal samples from both the Westmoreland and Shell mining areas.

Air Quality Sensitivity Screening Analysis: Sites 1 and 23. The final phase of the air quality screening analysis entailed a more detailed assessment of plant emission control sensitivities to the final coal gasification plant process design, the resultant plant gaseous and particulate emission characteristics, and the diffusional and transport properties of the emitted pollutant plume due to the location of the two selected sites, 1 and 23, with respect to the Class I air quality-designated Northern Cheyenne Reservation.

The final plant case design scenarios for purposes of this feasibility study are quite similar in nature to those adopted for the early preliminary screening analysis. As in the earlier analysis, the Case I plant design scenario assumes a plant production of 250 MM SCF/D SNG and generation of sufficient power for internal requirements only. The Case II plant design also assumes a 250 MM SCF/D SNG production capability but assumes that 40 percent fines in the coal feed are supplied to the boilers to produce additional electrical power for sale to the prospective electrical utility market.

The emissions data utilized in the sensitivity screening analysis are presented in Table 4.6.1-8 for an assumed Westmoreland coal feed and in Table 4.6.1-9 for an assumed Shell coal feed. The physical stack parameters utilized in the modeling analyses are shown in Table 4.6.1-10 and are based upon the results of the early preliminary screening analyses previously discussed.

EPA GEP Stack Height Regulations. During the time interval between the early preliminary screening analysis and the sensitivity screening analysis, new stack height regulations (Federal Register Vol. 47, No. 26, 8 February 1982) were invoked by the EPA under Section 123 of the Clean Air Act which was added by the 1977 Clean Air Act Amendments. Section 123 prohibits stacks taller than good engineering practice (GEP) height and other dispersion techniques from affecting the emission limitations required to meet the National Ambient Air Quality Standards (NAAQS) or PSD air quality increments. These regulations do not limit the physical stack height of any source, nor do they require any specific stack height for any source. Instead, they set limits on the maximum stack height credit to be used in ambient air quality modeling for the purpose of setting an emission limitation and calculating the air quality impact of a source. Sources are modeled at the physical stack height unless that height exceeds their GEP stack height. The regulations apply to all stacks constructed and all dispersion techniques implemented since 31 December 1970.

TABLE 4.6.1-8
FINAL AIR EMISSIONS SUMMARY:
WESTMORELAND COAL

Source	Particulates T/yr)	NO_x[1] (T/yr)	SO_2 (T/yr)	HC (T/yr)
Boiler Flue Gas				
Case I	382	6,860	2,610	-
(uncontrolled)	(117,920)	(Note 3)	(26,130)	-
Case II	1,140	20,600	7,840	-
(uncontrolled)	(353,800)	(Note 3)	(78,400)	-
Vent Gas Incinerator	-	1,790	1,680	-
(uncontrolled[4])	-	(Note 3)	(117,400)	(41,920)
Gasif. Lock Gas Vent	-	-	-	168
Gasif. Startup[2]	-	-	35	20
Coal Screening/Distribution				
Case I	48	-	-	-
Case II	56	-	-	-
Tank Farm	-	-	-	40
Tar Dist. Heater	-	49	-	-
Methanation - Cat. Red. Htr.[5]	-	1	-	-
Misc. Flare Pilots[6]	-	7	-	-
Wastewater Treating Incinerator[6]	-	2	-	-

NOTES:

(1) As NO_2

(2) Maximum emission rate: SO_2 744 lb/hr
Hydrocarbons 936 lb/hr

(3) Special burner required to achieve emission level

(4) SO_2 - no sulfur recovery
HC - no incineration

(5) Maximum NOx emission rate, 30 lb/hr

(6) Fuel gas use only

(7) Case I - Plant generates sufficient power for all internal needs and neither imports nor exports power.
Case II - Plant generates power in excess of internal needs assuming 40 weight percent coal fines fed to the boiler.

TABLE 4.6.1-9

FINAL AIR EMISSIONS SUMMARY:

SHELL COAL - CASE II

Source	Particulates T/yr)	NOx[1] (T/yr)	SO_2 (T/yr)	HC (T/yr)
Boiler Flue Gas	1,180	21,200	5,710	-
(uncontrolled)	(191,630)	(Note 3)	(35,700)	-
Vent Gas Incinerator	-	1,770	717	-
(uncontrolled[4])	-	(Note 3)	(53,700)	(52,500)
Gasif. Lock Gas Vent	-	-	-	223
Gasif. Startup[2]	-	-	16	23
Coal Screening/Distribution Case II	56	-	-	-
Tank Farm	-	-	-	64
Tar Dist. Heater	-	81	-	-
Methanation - Cat. Red. Htr.[5]	-	1	-	-
Misc. Flare Pilots [6]	-	7	-	-
Wastewater Treating Incinerator[6]	-	2	-	-

NOTES:

(1) As NO_2
(2) Maximum emission rate: SO_2 320 lb/hr; Hydrocarbons 1,100 lb/hr
(3) Special burner required to achieve emission level
(4) SO_2 - no sulfur recovery
HC - no incineration
(5) Maximum NOx emission rate, 30 lb/hr
(6) Fuel gas use only
(7) Case II - Plant generates power in excess of internal needs assuming 40 weight percent coal fines fed to the boiler.

TABLE 4.6.1-10

PHYSICAL STACK PARAMETERS

	Westmoreland Coal		Shell Coal
	Case I	Case II	Case II
Stack Height	625 ft.	625 ft.	250 ft.
Stack Diameter	30 ft.	42 ft.	42 ft.
Exit Gas Velocity	50 ft/sec	50 ft/sec	50 ft/sec
Volumetric Flow Rate	2,022,400 ACFM	4,237,400 ACFM	4,337,500 ACFM
Exit Gas Temperature	240°F	180°F	180°F

NOTE: Case I - Plant generates sufficient power for all internal needs and neither imports nor exports power.

Case II - Plant generates power in excess of internal needs assuming 40 weight percent coal fines fed to the boiler.

Determination of GEP Stack Height. The GEP stack height regulations establish several basic methods of calculating a source's GEP stack height, two of which are applicable to this analysis.

(1) De minimus height. EPA is adopting 65 meters (213 feet) as the minimum GEP stack height for all sources regardless of the size or location of any structures or terrain features. This height is intended to present a reasonable estimate of the height needed to ensure that emissions will not be affected by common ground-level meteorological phenomena which may produce excessive pollutant concentrations. Typical causes of these phenomena include surface roughness and the temperature changes caused by the solar heating and the terrestrial cooling cycle.

Virtually all significant sources of SO_2, for example, can justify stack height credits greater than 65 meters. Accordingly, the de minimus height will have little effect on atmospheric loadings of SO_2.

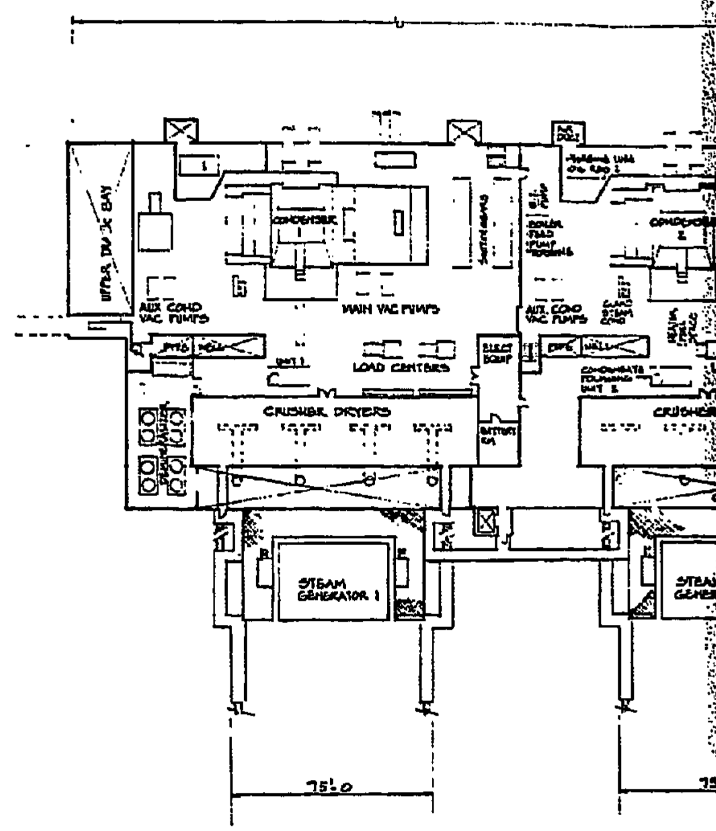
(2) Mathematical Formula. Excessive concentrations may be produced by downwash, wakes, and eddies caused by structures located near the stack. EPA is adopting two formulas with which to calculate the GEP stack height—one for stacks in existence on 12 January 1979 (the date of publication of EPA original proposed rules) and one for stacks constructed after that date.

For stacks in existence on 12 January 1979, EPA has adopted the traditional engineering formula of two and one-half times the height of the nearby structure ($H_g = 2.5H$). For stacks constructed after 12 January 1979 which would be applicable to the proposed Crow coal gasification plant, EPA has established a refined formula of the height of the nearby structure plus one and one-half times the height or width of the structure, whichever is less, ($H_g = H + 1.5L$) as the formula for determining the GEP stack height.

Inspection of the proposed synfuels plant layout as shown in Figures 4.6.1-2 and 4.6.1-3 and as discussed in more detail in Volume II of this report, reveals that the generator building is 250 feet in height and has minimum lateral dimensions which exceed the height. Therefore, applying the above formula, the GEP stack height, which can be used in conjunction with air quality dispersion modeling techniques is 625 feet—the physical stack height requirement derived for the candidate Site 1 scenarios in the early preliminary screening analysis and the assumed physical stack height for the Case I and Case II design scenarios, utilizing the Westmoreland coal, shown in Table 4.6.1-10 at Site 1 for this sensitivity screening analysis. Although this stack height credit could be applied in the air dispersion modeling analysis for the Case II design scenario utilizing the Shell coal supply at Site 23, the results of the sensitivity analysis, discussed in considerable detail in the next section, will demonstrate that this is not necessary for compliance with the 24-hour SO_2 Class I PSD within the boundaries of the Northern Cheyenne Reservation.

Sensitivity Analysis Results - Site 1 and Site 23. The initial efforts for the final air quality screening analysis centered on a confirmation of the earlier preliminary screening analysis results. This employed the updated plant process design and plant emission control efficiencies for SO_2 and particulate matter presented in Tables 4.6.1-8, 4.6.1-9, and 4.6.1-10 and the source-receptor terrain characteristics presented earlier in Table 4.6.1-1 for the selected Sites 1 and 23 and illustrated in Figures 4.6.1-4 and 4.6.1-5.

The initial phase of the sensitivity analysis as summarized in Table 4.6.1-11 confirmed the baseline case design scenarios I and II for both the Westmoreland and Shell coal supplies at candidate Site 1 for a maximum allowable GEP stack height of 625 feet. This assumes the baseline SO_2 emission control efficiency of 90 percent for boiler emissions and 98.6 percent efficiency for emissions emanating from the vent gas incinerator for the Westmoreland coal and baseline SO_2 control efficiencies of 84 percent and 98.7 percent, respectively, for the boiler and vent gas incinerator for the Shell coal scenarios.



	DATE	REVISION DESCRIPTION		
		ISSUED FOR STUDY		

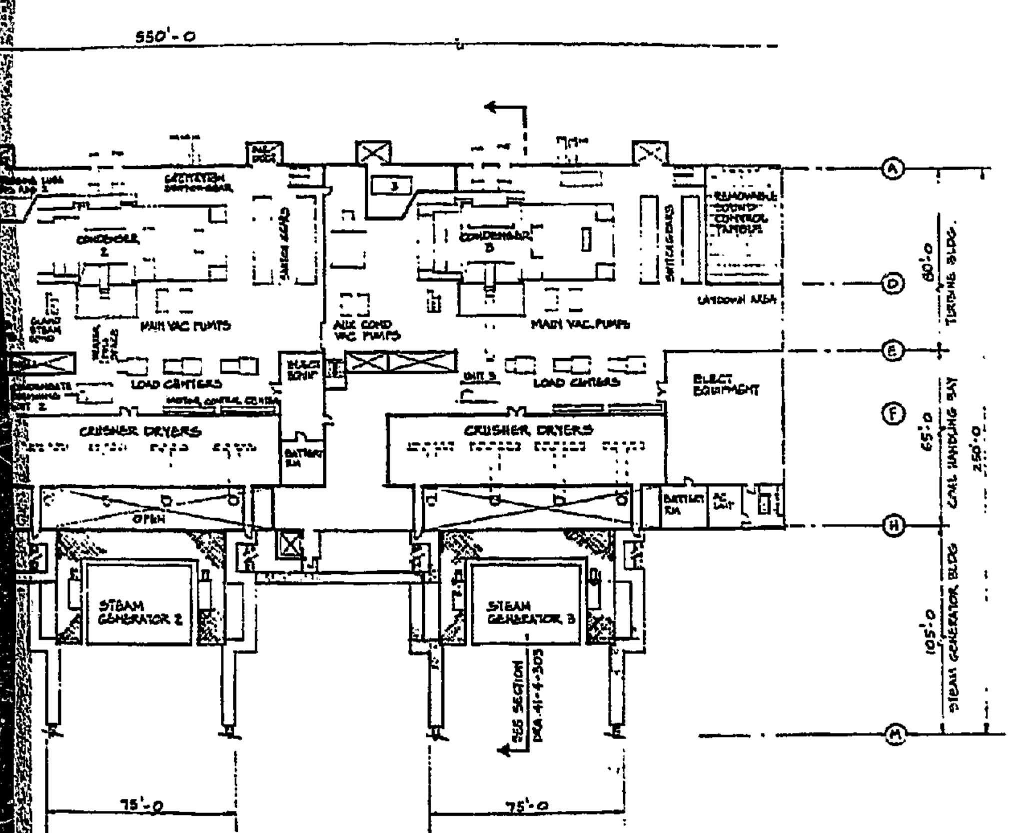


FIGURE 4.6.1-2

FLUOR

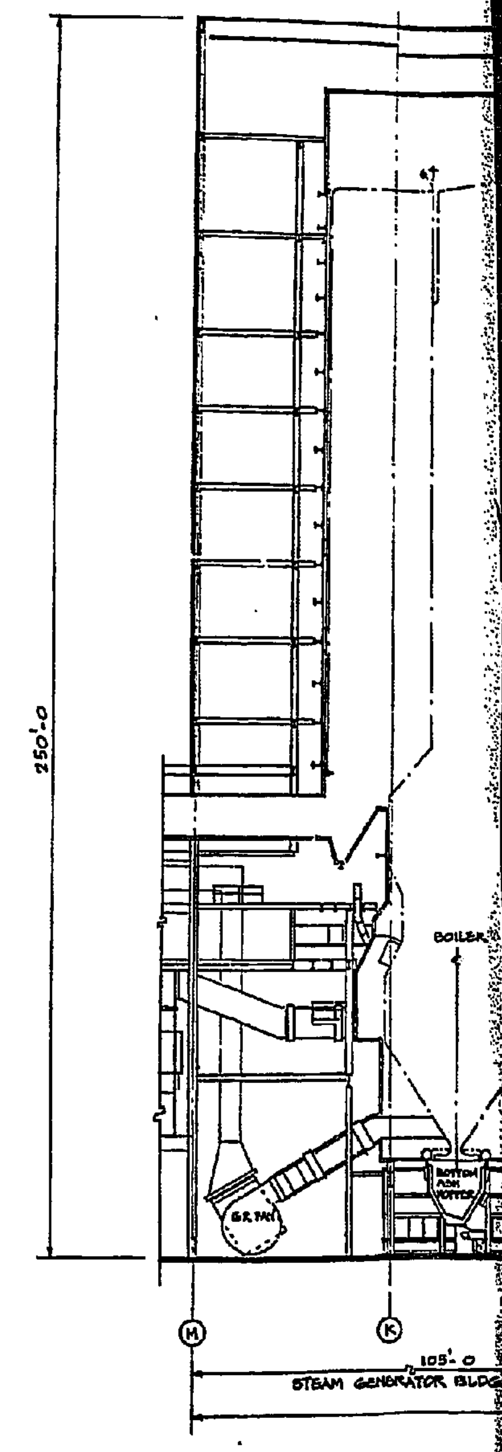
POWER GENERATION BUILDINGS
INTERMEDIATE FLOOR PLAN
SYNFUELS FEASIBILITY STUDY
CROW TRIBE OF INDIANS MONTANA

P. KIM	
M. DORN	
J. ADIBSI	5/12/82
M. DORN	
R. LANG	

1/32"=1'-0"

835704-41-4-302

1



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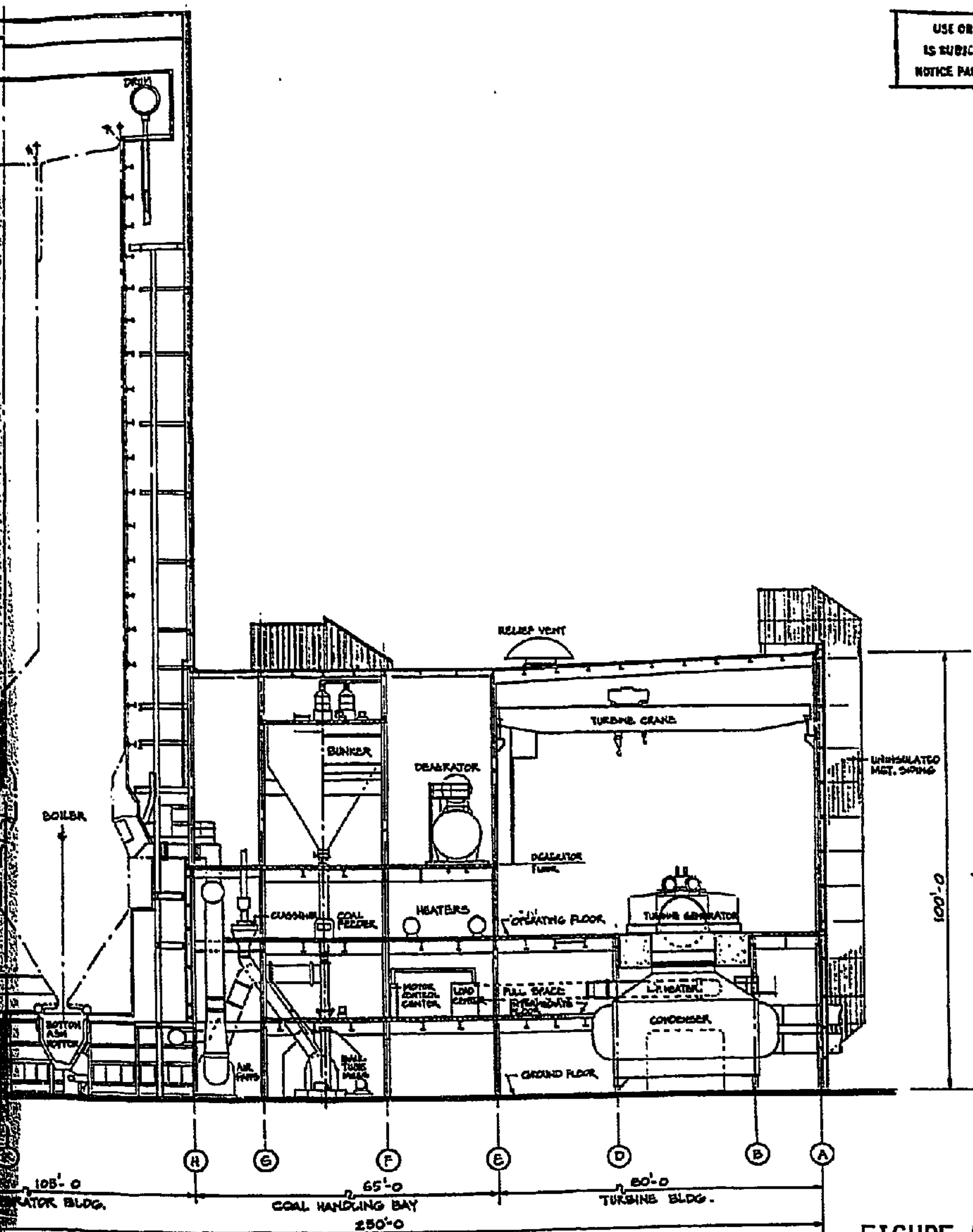


FIGURE 4.6.1-3

DWG. NO.	REFERENCE DRAWING

FLUOR

P. KIM		POWER GENERATION BUILDINGS SECTION	
M. DORN		SYNFUELS FEASIBILITY STUDY	
J. ADIBSI		CROW TRIBE OF INDIANS	MONTANA
M. DORN			
R. LANG	6/11/82		
		1/16"=1'-0"	835704-41-4-303	1

FIGURE 4.6.1-4
CROW SYNFUELS FEASIBILITY STUDY:
SITE 1, TERRAIN CONSIDERATIONS, VALLEY MODELING ANALYSIS

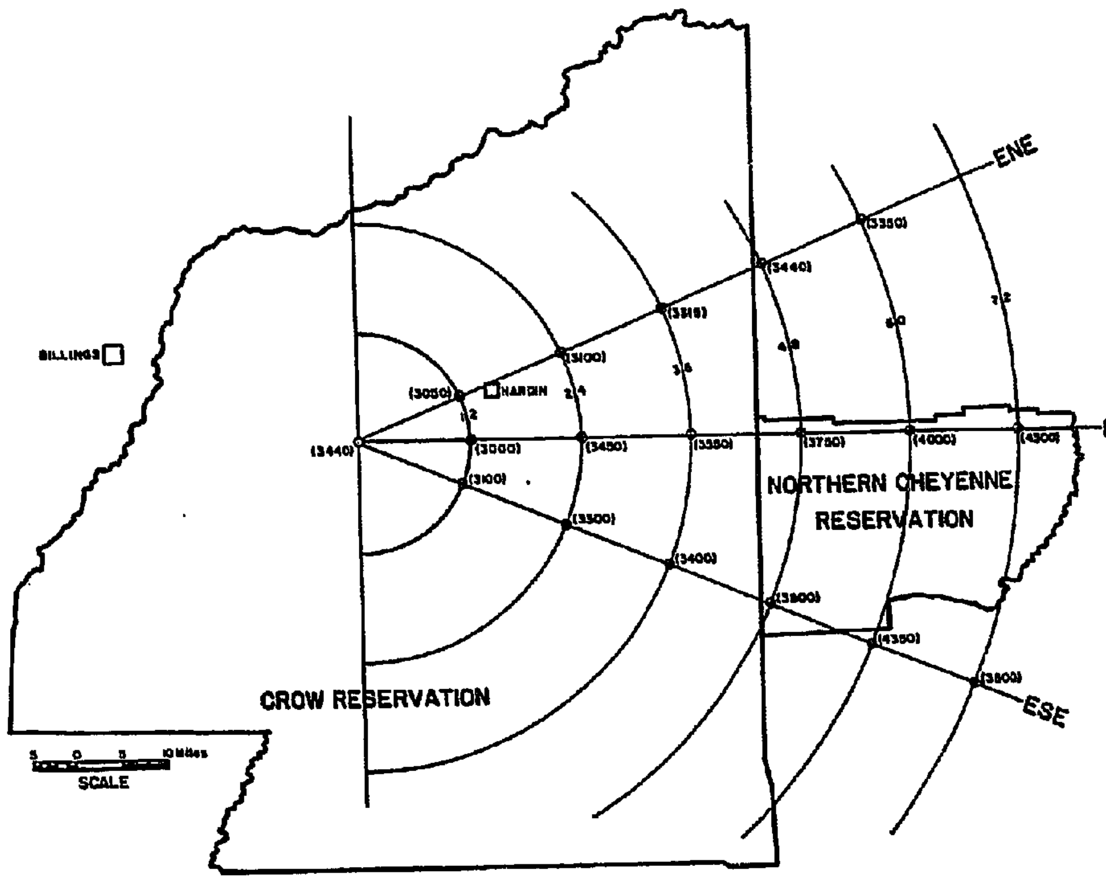
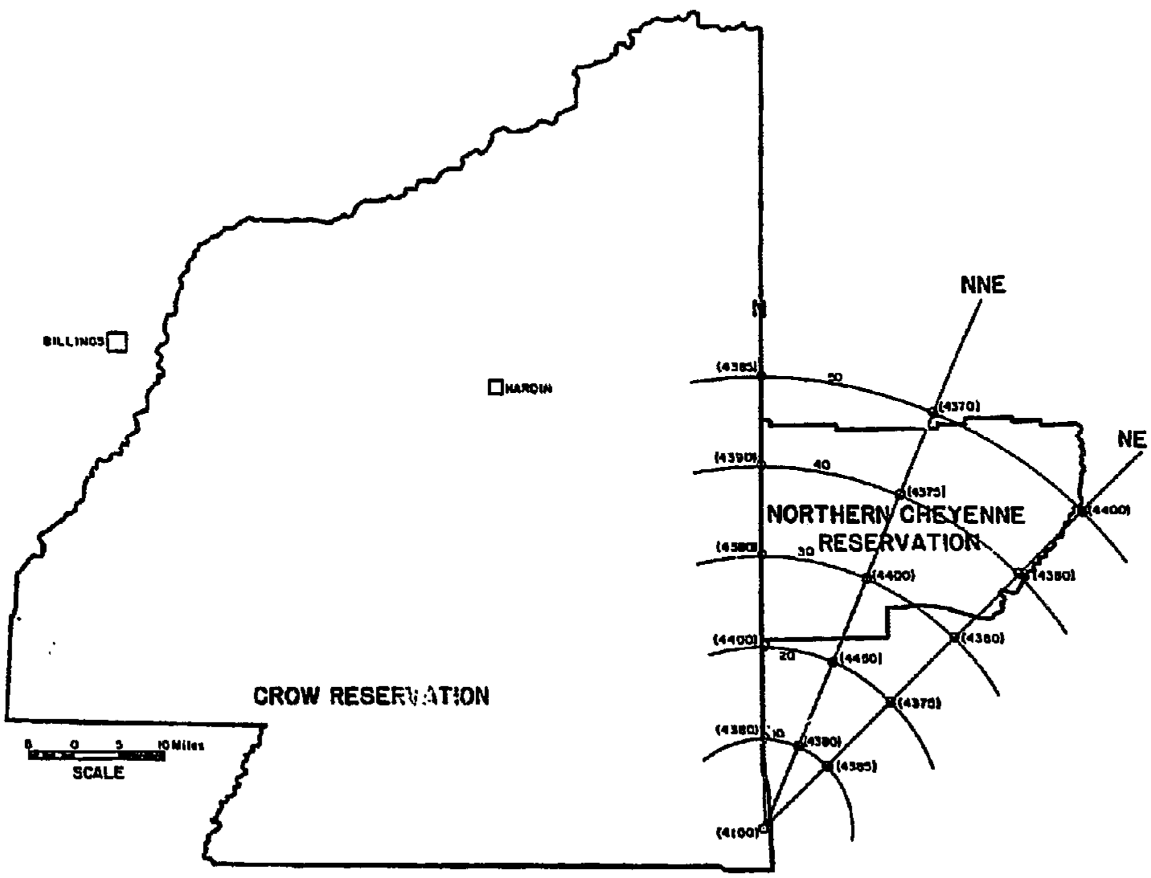


FIGURE 4.6.1-5
CROW SYNFUELS FEASIBILITY STUDY: SITE 23,TERRAIN CONSIDERATIONS, VALLEY MODELING ANALYSIS



- Radial distances in miles from source location.
- Source and receptor elevations in feet MSL in parentheses.

TABLE 4.6.1-11

FINAL SCREENING ANALYSIS SUMMARY: PLANT SO_2 CONTROL EFFICIENCIES AND PHYSICAL STACK HEIGHT REQUIREMENTS FOR 24-HOUR CLASS I PSD COMPLIANCE, CROW COAL GASIFICATION PLANT SITES 1 AND 23

		CASE I		CASE II	
Site ID	Coal Feed	Boiler SO_2 Control Efficiency, %	Physical Stack Height, ft	Boiler SO_2 Control Efficiency, %	Physical Stack Height, ft
1	Westmoreland	-	-	90[a]	625[a]
		-	-	90[a]	620[b]
		-	-	93.4[c]	520[c]
		84.5[d]	525[d]	93.3[d]	525[d]
	Shell			84[a]	625[d]
				84[a]	485[b]
				82[d]	525[d]
23	Shell			84[a]	625[a]
				70[e]	250[e]
				76.3[f]	213[f]

CASE I - 250 MM SCFD Plant Only.
CASE II - 250 MM SCFD Plant plus deliverable electric power for sale.

Vent gas incinerator SO_2 emission control efficiency - 98.7 percent for Westmoreland coal feed 98.7 percent for Shell coal feed - (baseline values held constant throughout sensitivity analysis).

a - original boiler SO_2 baseline emission control efficiencies, GEP Stack height credit allowance for dispersion modeling.

b - allowable physical stack height with boiler SO_2 baseline emission control efficiencies.

c - vendor-quoted maximum attainable boiler SO_2 emission control efficiency, minimum allowable physical stack height.

d - minimum boiler SO_2 emission control efficiencies for 525 feet stack height.

e - minimum boiler SO_2 emission control efficiency for original baseline physical stack height assumption.

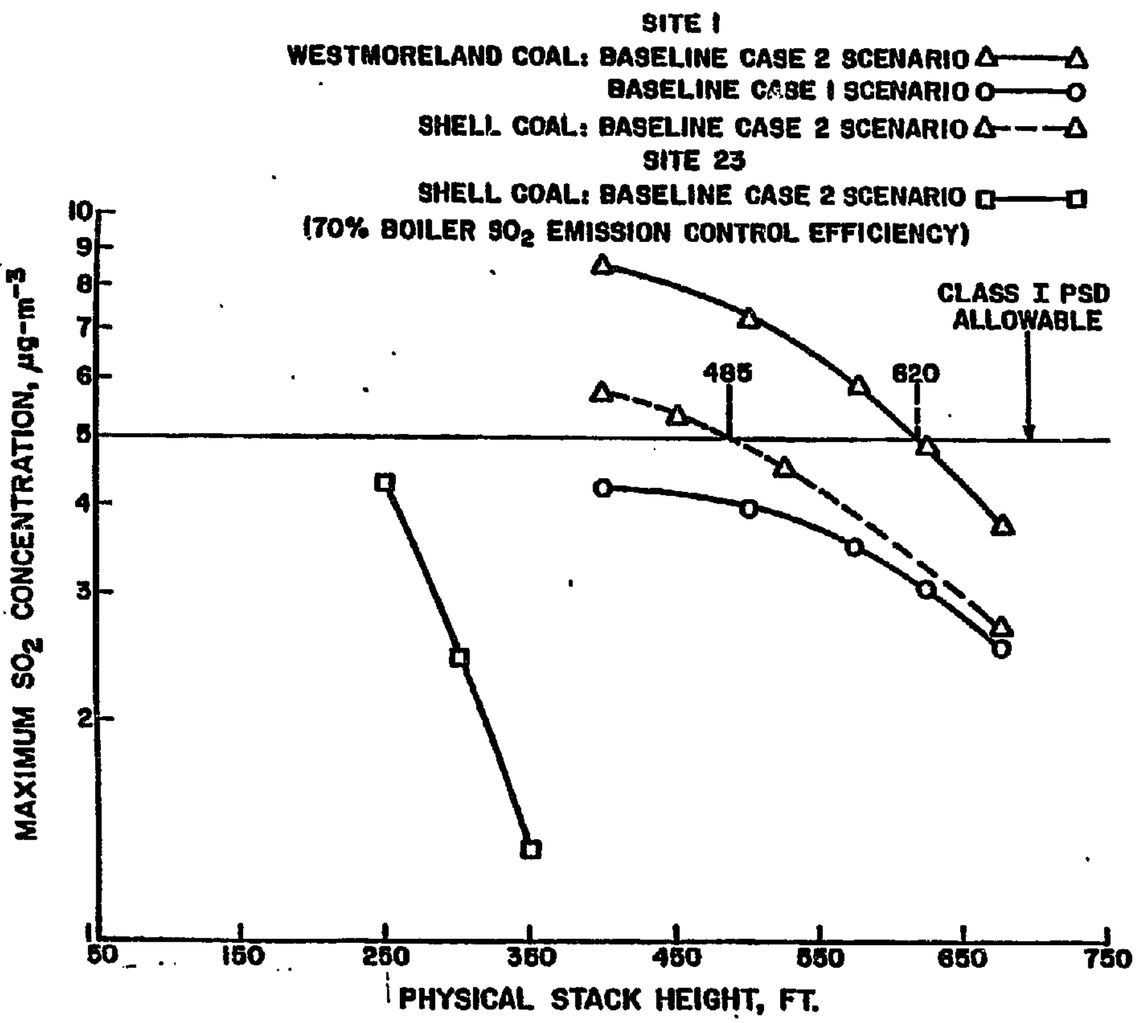
f - minimum boiler SO_2 emission control efficiency for de minimus GEP stack height.

Similarly, confirmation of compliance with the 24-hour SO_2 Class I PSD increment for the Case II design at candidate Site 23 was established for the Shell coal supply, assuming the baseline SO_2 emission control efficiency of 84 percent for boiler emissions and 98.7 percent for vent gas incinerator emissions and the allowable GEP physical stack height of 625 feet. The GEP stack height allowance could be used for dispersion modeling purposes for the Case II design scenario at Site 23. But the results of the sensitivity analysis illustrate (1) in Figure 4.6.1-6 that the SO_2 emission control efficiency for boiler emissions can be reduced to 70 percent with the assumed baseline stack height of 250 feet, previously presented in Table 4.6.1-10, and (2) comply as well with the 24-hour SO_2 Class I PSD increment. An SO_2 emission control efficiency of 70 percent for boiler emissions for the Case II design utilizing Shell coal at Site 23 probably sets the lower limit for this scenario since this represents the minimum control requirement to comply with New Source Performance Standards (NSPS) for large stationary coal-fired power plants of less than 0.6 pounds of SO_2/MMBtu. Although there are presently no existing NSPS requirements for coal gasification plants, the Case II design scenario postulates the production of appreciable quantities (250 to 280 MW) of electrical power for sale to prospective electrical utilities. Hence, it is possible that, within the framework of the Case II design scenario, the facilities would have to comply with NSPS.

A sensitivity analysis was also performed for both Case I and Case II design scenarios at candidate Site 1 to determine the minimum allowable physical stack height necessary to comply with the 24-hour Class I PSD increment for the Westmoreland coal supply assuming the baseline SO_2 emission control efficiencies. The results, presented in Table 4.6.1-11 and Figure 4.6.1-6 demonstrate that any physical stack height greater than or equal to 620 feet would meet the Class I PSD requirement. Figure 4.6.1-6 illustrates that the Case I design scenario is relatively insensitive to change in physical stack height over the range of 350 to 650 feet and would achieve Class I PSD compliance for SO_2 emissions with the assumed baseline control efficiencies over that range of values. The use of the Shell coal supply at Site 1 for the Case II design scenario employing the baseline SO_2 emission control efficiencies of 84 percent and 98.7 percent for boiler and vent gas incinerator emissions, respectively, resulted in a somewhat lower requirement than Case II for Westmore-

FIGURE 4.6.1-6

PRELIMINARY COMPARISION OF PHYSICAL STACK HEIGHT REQUIREMENTS FOR CLASS I PSD COMPLIANCE: BASELINE DESIGN CASE SCENARIOS I AND II, SITES 1 AND 23



land coal utilization requiring a physical stack height greater than or equal to 485 feet in order to comply with the 24-hour SO_2 Class I PSD increment. It must be emphasized, however, that the Westmoreland Absolaka Mine is the intended primary source of coal supply for all Site 1 scenarios.

A review of possible vendors for flue gas desulfurization (FGD) systems has indicated that one potential supplier has quoted an achievable upper limit (BACT) of 93.4 percent SO_2 emission control efficiency in the assumed 1985 to 1990 time frame for the final design and construction phase of this project. Upward adjustment of 90 percent SO_2 emission control efficiency to 93.4 percent for boiler emissions would affect a reduction of 100 feet in the minimum physical stack height requirement; i.e., from 620 feet to 520 feet as shown in Figure 4.6.1-7, for plant designs utilizing a Westmoreland coal supply at candidate Site 1. The above result assumes that the baseline SO_2 emission control efficiency for the vent gas incinerator retains a baseline value of 98.6 percent.

An additional series of sensitivity analyses were performed for both case design scenarios at candidate Sites 1 and 23 for assumed constant but possibly attainable minimum physical stack heights and constant values for SO_2 emission control efficiencies for the vent gas incinerator effluents.

From previously discussed results shown in Figure 4.6.1-7 it has been shown that the Case II design scenario utilizing the Westmoreland coal supply establishes a possibly future attainable limit for SO_2 Class I PSD compliance at Site 1 of 93.4 percent SO_2 emission control efficiency for the boiler emissions and a physical stack height of 520 feet. Therefore, assuming the slightly more conservative value of 525 feet for the plant physical stack height, Figure 4.6.1-8 illustrates that greater than or equal to 93.3 percent boiler SO_2 emission control efficiency would be required to comply with the 24-hour SO_2 Class I PSD increment. For the same set of initial assumptions, it is shown that greater than or equal to 84.5 percent SO_2 emission control efficiencies would be required for Class I PSD for the Case I design at Site 1 utilizing Westmoreland coal as shown in Figure 4.6.1-8. Similarly, the use of Shell coal for the Case 2 design scenario would, in turn, necessitate greater than or equal

FIGURE 4.6.1-7

MINIMUM STACK HEIGHT REQUIREMENTS FOR MAXIMUM ATTAINABLE BOILER SO_2 EMISSION CONTROL EFFICIENCY: WESTMORELAND COAL, DESIGN CASE II, SITE 1

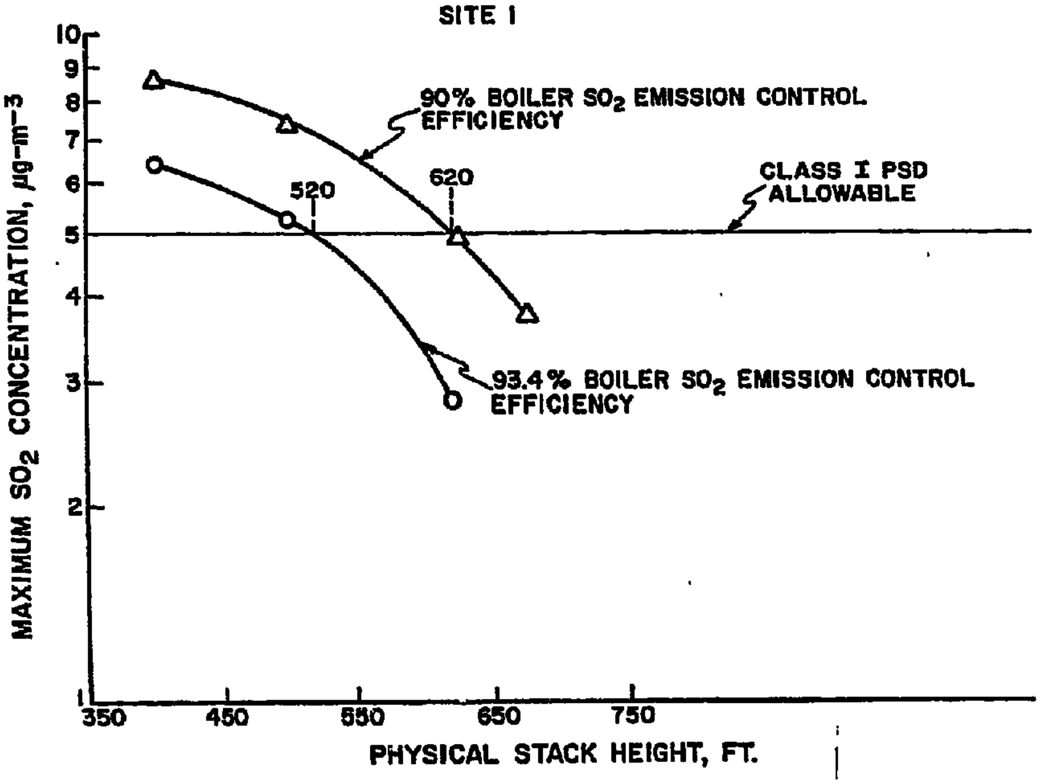


FIGURE 4.6.1-8

MINIMUM ACHIEVABLE SO_2 EMISSION CONTROL EFFICIENCIES FOR MINIMUM PHYSICAL STACK HEIGHTS, SITES 1 AND 23