MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OPERATING PERMIT TECHNICAL REVIEW DOCUMENT

Permitting and Compliance Division
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Yellowstone Energy Limited Partnership
2215 N. Frontage Road
Billings, Montana 59101-7303

The following table summarizes the air quality programs testing, monitoring, and reporting requirements applicable to this facility.

Facility Compliance Requirements	Yes	No	Comments
Source Tests Required	X		Methods 5, 6, 7, 9
Ambient Monitoring Required	X		
COMS Required	X		Opacity
CEMS Required	X		SO_2, NO_x, CO
Schedule of Compliance Required		X	
Annual Compliance Certification and Semiannual Reporting Required	X		
Monthly Reporting Required		X	
Quarterly Reporting Required	X		Monthly emission reports from the required monitors are to be submitted quarterly.
Applicable Air Quality Programs			
ARM Subchapter 7 Preconstruction Permitting	X		Permit #2650-06
New Source Performance Standards (NSPS)	X		Subpart Da, Kb, OOO
National Emission Standards for Hazardous Air Pollutants (NESHAPS)			No except for 40 CFR 61 Subpart M
Maximum Achievable Control Technology (MACT)		X	
Major New Source Review (NSR)/ Prevention of Significant Deterioration (PSD)	X		The initial permit issued to YELP was subject to both NSR and PSD. YELP has not triggered a NSR/PSD review since that time.
Risk Management Plan Required (RMP)		X	
Acid Rain Title IV		X	
State Implementation Plan (SIP)	X		June 1998, March 2000 Stipulation

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SECTION I. GENERAL INFORMATION

A. Purpose

This document establishes the basis for the decisions made regarding the applicable requirements, monitoring plan, and compliance status of emissions units affected by the operating permit proposed for this facility. The document is intended for reference during review of the proposed permit by the EPA and the public. It is also intended to provide background information not included in the operating permit and to document issues that may become important during modifications or renewals of the permit. Conclusions in this document are based on information that was provided in the original application submitted by Yellowstone Energy Limited Partnership (YELP) on June 12, 1996, and additional submittals dated January 29, 1997, and October 13, 1999.

B. Facility Location

The YELP complex is located in Yellowstone County, Montana, north of Lockwood and approximately four miles northeast of downtown Billings. The facility is located within the boundaries of the Exxon Refinery.

The immediate area, within a few hundred meters of the plant is characterized as flat terrain, the surrounding comprised of a valley which runs southwest to northeast. The valley follows the Yellowstone River as it passes to the northwest. Complex terrain effectively parallels the river, mainly to the south of the plant site and follows the same river orientation.

The climate of the area is typical continental and semi-arid. Rainfall in the vicinity of the complex is less than 15 inches per year with most precipitation occurring from spring through early fall. Winds are moderate with the predominate direction from the southwest.

C. Facility Background Information

The original preconstruction Permit **#2650** was issued to Billings Generation Inc. (BGI) on December 13, 1991, for the construction of an electrical power generating and steam cogeneration facility. The application was originally submitted on July 6, 1990. Because the facility was considered a major source, the application was subject to New Source Review and the requirements of the Prevention of Significant Deterioration (PSD) program. BGI was the application submittee and Bison Engineering Inc. was the environmental consultant performing the air quality permitting analyses. The application was deemed complete on November 8, 1991, contingent upon acceptable modifications to existing Exxon Refinery permits because offsets of SO_2 emissions from the Exxon facility were required before construction of the BGI facility could be authorized.

The petroleum coke-fired power plant originally had a name plate rating of 49.5 megawatts and would produce approximately 42 net megawatts of electrical power generation. Gaseous emissions and particulates from the Exxon coker process unit are then fired in the combustors. The BGI power plant provides cogenerated steam energy for the Exxon Refinery.

The project included the construction of the BGI facility and some modifications at the Exxon Refinery Coker-CO boiler. The modifications at the Refinery included the installation of flue gas duct work to divert the coker unit process gas from the existing Coker-CO boiler to the BGI facility. In addition, fluid coke was to be diverted from the Coker CO boiler and to be pneumatically fed to the BGI facility and finally steam pipelines between BGI and Exxon facilities were added.

An air-cooled condenser (ACC) along with a service cooling water cooling tower is used by the BGI power plant. Water resource demand at the plant is minor with an ACC system. Potable water requirements as well as service cooling water are available from the local water users association.

An additional 99 tons per year of SO_2 emission reduction may be realized from the Exxon Refinery. The source of this reduction at the refinery will come from high sulfur fuel oil burning. The annual SO_2 offset or net SO_2 reduction that can be expected from this overall project is 238 tons (BGI and Exxon coker gas).

Permit **#2650-01** was issued to BGI on March 11, 1992. BGI requested a modification to support SO_2 emission reductions in conjunction with the EXXON refinery and Permit Modification #1564-03. The modified BGI permit addressed EPA concerns in the original Permit (#2650). The request was addressed under the provisions of Subchapter 11, ARM 16.8.1113(1)(b). The changes addressed verification of required offsets from the Exxon facility, contingency measures if the offsets are not met and additional modeling performed to verify that the project would not cause significant impacts to the NAAQS.

Permit **#2650-02** was issued March 25, 1993, to change the design of the facility from one main baghouse controlling the boilers exhausting through two stacks to two baghouses exhausting through one stack.

Permit Alteration **#2650-03** was issued on December 23, 1995, to change the name of the facility from BGI to YELP; to allow the burning of other petroleum cokes and cat slurry oil in the boilers as alternative fuels; to make the permit consistent with the stipulation signed between the Department and YELP; to change the description of the facility to include the current plant design which eliminated the parasitic load formerly driven by steam in the plant; to remove the lb/MMBtu requirements from some of the limits contained in Section II.I. of the permit; to clarify the requirements of Section II.I.5; to identify the requirements references more clearly; and to remove the requirement limiting the sulfur content of the petroleum coke.

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Permit Modification **#2650-04** was issued on May 18, 1996, to change the coke sampling and analysis requirements for the facility. Previously, YELP had been required to sample the coke supply to the boilers on a daily basis for sulfur content and heating value. YELP has shown by this sampling that there is little variability in the sulfur content of the coke and the Department has agreed that weekly sampling will be sufficient to demonstrate compliance with applicable requirements. This modification did not result in an increase in the emissions of any pollutant from the facility.

Permit Alteration **#2650-05** was issued on December 26, 1999, for the addition of an enclosed petroleum coke unloading/crushing/processing plant and a processed petroleum coke storage and handling building (Coke Barn) to the existing permitted equipment. Further, YELP requested an extension of time, under the general permit conditions, to install the Cat Slurry oil tank.

Permit Modification **#2650-06** was issued on February 11, 2000, to correct referencing errors that needed to be corrected prior to the issuance of the Title V operating permit for the YELP facility.

HB 311, the Montana Private Property Assessment Act, requires analysis of every proposed state agency administrative rule, policy, permit condition or permit denial, pertaining to an environmental matter, to determine whether the state action constitutes a taking or damaging of private real property that requires compensation under the Montana or U.S. Constitution. As part of issuing an operating permit, the Department is required to complete a Taking and Damaging Checklist. As required by 2-10-101 through 105, MCA, the Department has conducted a private property taking and damaging assessment and has determined there are no taking or damaging implications. The checklist was completed on October 29, 1999; a copy is available YELP's files.

D. Compliance Designation

The first annual inspection for this facility was conducted on August 6, 1996. The plant start-up date was June 26, 1995. The plant successfully conducted the initial NSPS performance and CEMs certification tests. The main stack and plant-wide emissions were deemed to be in compliance on the inspection date. The actual emission data taken from the CEMs\CERMs and emission compliance testing were used as the basis for this determination. However it was noted in the inspection notes that the coke handling and transfer operation that takes place at the Exxon refinery needs some further attention which includes, but is not limited, to reducing the coke dust emissions from the active coke pile area. Under strong north- northwest winds, this coke pile becomes an uncontrolled fugitive source that impacts the Montana Sulphur & Chemical Company plant.

The second annual compliance inspection was conducted on July 29, 1997. The main stack and plant-wide emissions were deemed to be in compliance on the inspection date. The actual emissions data taken from the CEMs\CERMs and emissions compliance testing were used as the basis for this determination. However, it was noted that housekeeping activities in regards to controlling particulate matter needed some urgent attention. All of the plant's storage silos and material transfer points exhibited signs of material losses. This includes fly ash, bottom ash, limestone and coke material. In addition, strong SO_2 odors were noticed throughout the boiler house area, which is an indication that boiler gases were escaping.

The Department issued a Notice of Violation letter on June 11, 1997, for seven alleged air quality permit and NSPS violations. The violations included five SO_2 emission violations occurring on December 23, and 24 1996, and January 13, April 6, and April 10, 1997, and an opacity violation occurring on December 30, 1997; and a failure to comply with air quality reporting requirements incorporating NSPS 40 CFR Part 60, Subpart Da, Sections

60.40a – 60.49a (Permit #2650-04 Section III.B). Administrative Order and Stipulation , Docket No. AQ-98-08 (FID#130) was settled with an administrative penalty of $45,915 on December 12, 1998.

The third annual inspection was conducted on June 30, 1999. The main stack and plant-wide emissions were deemed to be in compliance on the inspection date.

SECTION II. SUMMARY OF EMISSION UNITS

A. Facility Process Description

The primary operation of the YELP complex is the production of energy in the form of steam. The plant, a 65 Megawatt electric generating facility uses both petroleum coke and coker gas as the primary fuels to fire two circulating fluidized bed combustion (CFBC) boilers. These boilers in turn produce steam of which a portion is provided to the Exxon Refinery, a small portion is used to run various fans and pumps at the site and the remainder is used to generate electricity through a steam turbine. The facility consumes approximately 224,300 tons per year of coke.

Sulfur Dioxide (SO_2) emissions are controlled through limestone injection into the CFBC boilers. Limestone injection fits well with the design of a CFBC boiler and provides for a substantial reduction in these emissions. The limestone upon reaching a high enough temperature calcines to lime. Lime reacts with SO_2 to form calcium sulfites and calcium sulfates. These compounds are contained in the gas stream as particulates. The system is designed to remove a minimum of 92% of the incoming sulfur compounds.

Particulate emissions from the CFBC units are controlled via baghouses. The baghouses are downstream of the CFBC boilers just prior to the stack. The baghouses serve the purpose of removing over 99% of the incoming particulate stream, including sulfur particulate.

NO_2, VOC and CO emissions are controlled through the CFBC design. The CFBC system, by design, operates at lower temperatures than a standard pulverized coal/coke system. One of the primary mechanisms that produces NO_2 is a high combustion temperature. The CFBC system operates at a lower temperature and thus produces less NO_2 than its counterpart systems. The CFBC boiler by its own design is a "low NO_x" burner.

Limestone is delivered to this facility from the quarry by truck. The material is unloaded (bottom dumped) inside an enclosed area, crushed, then conveyed into a storage silo. From the silo, limestone is added to the boiler thorough a closed system. Particulate emissions are controlled by the baghouse system.

Petroleum coke (coke) is supplied to the plant from two sources. The first is production coke from the Exxon refinery's coker unit. As coke is manufactured at the refinery, it will be pneumatically conveyed from a storage silo at the Exxon property to the coke storage silos at YELP. If the storage silos are full, the coke can be transferred to an open storage pile. The coke can then be supplied from the existing coke inventory by pneumatically conveying the coke from the silos, or from the open storage pile by using a front-end loader and transferring the coke to a hopper at the storage silo. In addition, petroleum coke may be delivered by truck from other suppliers. Coke from suppliers not requiring screening and sizing is unloaded from the trucks pneumatically via a truck fill line, particulate emissions from this activity are controlled by baghouses at the two coke silos.

Coke from suppliers requiring additional crushing or screening is delivered in bottom dump trucks. These trucks use the same unloading facility used by the limestone delivery trucks. Coke is resized using the limestone crushing equipment before it is pneumatically conveyed from the crusher to the pneumatic header. Emissions from the truck unloading and crushing are controlled by the baghouse system. All baghouses at the site are either a fabric or cartridge type filter unit.

Bottom ash is collected at the boiler and conveyed to a storage silo equipped with a baghouse. Baghouse solids are also transferred to this silo. The ash and solids are transported via covered trucks to the limestone quarry for disposal.

Fluid catalytic cracking slurry oil (CAT slurry oil), an Exxon Refinery product, is also an optional fuel source, transferred from the Exxon storage tanks to a 14,000 gal tank at YELP. The CAT slurry oil would be kept at approximately 200 °F, by circulating the slurry through a heat exchanger heated by low pressure steam, keeping the oil viscous and flowing. Fuel for the boilers can be taken from the heat exchanger return line and routed through a ring header at the boilers.

B. Categorically Insignificant Sources/Activities

All emission units were identified by YELP as significant in the operating permit application. The Department determined several emission units listed in the table in Appendix B were insignificant emissions unit. YELP is not required to update a list of insignificant emission units; therefore, the emission units and/or activities may change from those specified in Appendix B.

SECTION III. PERMIT CONDITIONS

A. Emission Limits and Standards

There are no emission limits or standards identified in this permit that were not previously applicable to the facility either by rule, permit or by the BER Order signed on June 12, 1998. The rule citations for all emission limits are included in the operating permit.

Opacity

This permit requires that a CEMS be installed on the main stack for the two Circulating Fluidized Bed Combustion (CFBC) boilers. For the remainder of sources included in the operating permit a Method 9 will be required as requested by the Department. The remaining sources include baghouses and fugitive sources. It was determined that these sources are not likely to violate the opacity limits and thus a Method 9 test would not provide any environmental benefit.

Particulate Matter

This permit requires annual Method 5 tests for the main stack. Method 5 tests are required every 4-years for the baghouses with 0.01 gr/dscf emission limits. For the remaining fugitive sources, Method 5 tests will be performed as requested by the Department.

SO_2 Emission Limits

YELP has established emission limits for the Main stack where the CFBC boiler emissions are vented. These limits are the result of the permit, Stipulation, and the NSPS standards. YELP is required to operate a SO_2 CEMs and perform annual testing (Method 6/6C) to demonstrate compliance with the emission limits.

NO_x Emission Limits

YELP has established emission limits for the Main stack where the CFBC boiler emissions are vented. These limits are the result of the permit and the NSPS standards. YELP is required to operate a NO_x CEMs and perform annual testing (Method 7/7E) to demonstrate compliance with the emission limits.

CO Emission Limits

YELP has established emission limits for the Main stack where the CFBC boiler emissions are vented. These limits are the result of the permit and the NSPS standards. YELP is required to operate a CO CEMs and perform annual testing (Method 3/3B) to demonstrate compliance with the emission limits.

B. Monitoring Requirements

ARM 17.8.1212(1) requires that all monitoring and analysis procedures or test methods required under applicable requirements are contained in operating permits. In addition, when the applicable requirement does not require periodic testing or monitoring, periodic monitoring must be prescribed that is sufficient to yield reliable data from the relevant time period that is representative of the source's compliance with the permit.

The requirements for testing, monitoring, recordkeeping, reporting, and compliance certification sufficient to assure compliance do not require the permit to impose the same level of rigor for all emissions units. Furthermore, it does not require extensive testing or monitoring to assure compliance with the applicable requirements for emission units that do not have significant potential to violate emission limitations or other requirements under normal operating conditions. When compliance with the underlying applicable requirement for a insignificant emission unit is not threatened by lack of regular monitoring and when periodic testing or monitoring is not otherwise required by the applicable requirement, the status quo **(i.e., no monitoring)** will meet the requirements of ARM 17.8.1212(1). Therefore, the permit does not include monitoring for insignificant emission units.

The permit includes periodic monitoring or recordkeeping for each applicable requirement. The information obtained from the monitoring and recordkeeping will be used by the permittee to periodically certify compliance with the emission limits and standards. However, the Department may request additional testing to determine compliance with the emission limits and standards.

C. Test Methods and Procedures

The operating permit may not require testing for all sources if routine monitoring is used to determine compliance, but the Department has the authority to require testing if deemed necessary to determine compliance with an emission limit or standard. In addition, the permittee may elect to voluntarily conduct compliance testing to confirm its compliance status.

D. Recordkeeping Requirements

The permittee is required to keep all records listed in the operating permit as a permanent business record for at least five years following the date of the generation of the record.

E. Reporting Requirements

Reporting requirements are included in the permit for each emissions unit and Section V of the operating permit "General Conditions" explains the reporting requirements. However, the permittee is required to submit semiannual and annual monitoring reports to the Department and to annually certify compliance with the applicable requirements contained in the permit. The reports must include a list of all emission limit and monitoring deviations, the reason for any deviation, and the corrective action taken as a result of any deviation.

F. Public Notice

In accordance with ARM 17.8.132, a public notice was published in the *Billings Gazette* newspaper on or before from February 16, 2000. The Department provided a 30-day public comment period on the draft operating permit from February 16, 2000, through March 17, 2000. ARM 17.8.1232 requires the Department to keep a record of both comments and issues raised during the public participation process. The Department did not receive any comments other than those submitted by YELP.

G. Draft Permit Comments

On March 17, 2000, the Department received comments from YELP on the Public Comment Draft Operating Permit #OP2650-00 for their facility. Those comments and the Department's response are included in the following table.

Summary of YELP's Comments

Permit Reference	YELP's Comment	Department Response
Throughout the permit	YELP assumes that references to data and observations being recorded in a log refer to "log" as a general term in that the required information could be logged into a computer, logbook, worksheets, etc.	The Department agrees that YELP may use electronic logging of information where possible or other appropriate methods of recording data and observations.
Section III.B, Table EU07	It appears that there is a typographical error in the table in that the two activities "SO_2 – Burning Coker Gas" and "SO_2 – Not Burning Coker Gas" are reversed and need to be relabeled.	The correction has been made in the permit.
Section III.E.12	YELP requests that the requirements for a "logbook" and the entry persons initialization be deleted and replace with more general language.	The correction has been made in the permit.
Section III.E.12	YELP requests that the requirement to maintain records based on the monthly amount of coke processed and stored be changed to the monthly amount of coke received. The requirement in question corresponds to the yearly coke throughput limit.	The correction has been made in the permit.
Section III.B.12	YELP requests that the weight percent of sulfur and heating value (BTU/lb) of petroleum coke be analyzed on a monthly basis, instead of a weekly basis based on a data analysis provided in the comments.	The Department agrees that monthly sampling seems representative, and has changed the requirement in the permit from weekly to monthly.

Summary of EPA Comments

Permit Reference	EPA Comment	Department Response

SECTION IV. NON-APPLICABLE REQUIREMENT ANALYSIS

Pursuant to ARM 17.8.1221, YELP requested a permit shield for all non-applicable regulatory requirements and regulatory orders identified in the tables in Section 8 of the permit application. In addition, the YELP permit application identified a permit shield request for applicable requirements for both the facility and for certain emission units. The Department has determined that the requirements identified in the permit application for the individual emissions units are non-applicable. These requirements are contained in the permit in Section IV- Non-applicable Requirements.

The following table outlines those requirements that YELP had identified as non-applicable in the permit application but will not be included in the operating permit as non-applicable. The table includes both the applicable requirement and reason that the Department did not identify this requirement as non-applicable.

Applicable Requirement	Reason for Not Including
40 CFR 50 National Primary and Secondary Ambient Air Quality Standards	This rule has been excluded from Title V as an applicable requirement. However, the rule can be used to impose specific requirements on a major source.
40 CFR 51 Requirements for Preparation, Adoption, and Submittal of Implementation Plans 40 CFR 58 Ambient Air Quality Surveillance 40 CFR 71 Federal Operating Permit Programs	These rules contain requirements for the regulatory authorities and not major sources. However, these rules can be used to impose specific requirements on a major source.
40 CFR 52 Approval and Promulgation of Implementation Plans	This rule contains requirements that are always relevant to a major source.
40 CFR 62 Approval and Promulgation of State Plans for Designated Facilities and Pollutants	Because this rule contains requirements for regulatory authorities and not major sources, this rule can be used to impose specific requirements on a major source.
40 CFR 70 State Operating Permit Programs	This rule has specific requirements and may or may not be relevant to a major source.

Applicable Requirement	Reason for Not Including
Administrative Rules of Montana	
ARM 17.8.120 Variance Procedures *et. seq*. ARM 17.8.818 - 828 PSD Permitting Requirements ARM 17.8.804 Ambient Air Increments ARM 17.8.705 - 706 Permit, Construction, and Operation of Air Contaminant Sources - When Permit Required Exclusions and New or Altered Sources and Stacks ARM 17.8.708 Permit, Construction, and Operation of Air Contaminant Sources - Notification of Emissions Increase ARM 17.8.710 Permit, Construction, and Operation of Air Contaminant Sources - Conditions for Issuance of Permit ARM 17.8.715 Permit, Construction, and Operation of Air Contaminant Sources - Emission Control Requirements ARM 17.8.720 Permit, Construction, and Operation of Air Contaminant Sources - Public Review of Permit Application ARM 17.8.733 - 734 Permit, Construction, and Operation of Air Contaminant Sources - Modification of Permit and Transfer of Permit	These are procedural rules that have specific requirements that may become relevant to a major source during the permit term.
ARM 17.8.610 , 611 and 612- Open Burning Fees - Major Open Burning Source Restrictions, Emergency Open Burning Permits, Conditional Air Quality Open Burning Permits ARM 17.8.1106 - 1107 Visibility Impact Analysis and Models ARM 17.8.1110 - 1111 Visibility Monitoring and Additional Impact Analysis ARM 17.8.1704 - 1705 Permit Requirements for Major Stationary Sources or Modification Located Within Nonattainment Areas	These are procedural rules that have specific requirements that may become relevant to a major source during the permit term

Applicable Requirement	Reason for Not Including
ARM 17.8.1804-1806 Preconstruction Permit Requirements or major Stationary Sources or Major Modifications Located Within Attainment or Unclassified Areas - Additional Conditions, Review of Specified Sources, Baseline for Determining Offsets ARM 17.8.1905, 1907,1908 Air Quality Permit Application, Operation, And Open Burning Fees – Air application Fees, Air Quality Open Burning Fees, Air Quality Open Burning Fees for Conditions Open Burning Permits	
ARM 17.8.204 Ambient Air Monitoring ARM 17.8.716 - 717 Permit, Construction, and Operation of Air Contaminant Sources - Inspection of Permit and Compliance with Other Statutes and Rules ARM 17.8.326 Emission Standards - Prohibited Materials for Wood or Coal Residential Stoves	These are rules that are always applicable to major sources and may contain specific requirements for compliance.
ARM 17.8.1101 - 1103 Visibility Impact Assessment - Definitions, Applicability, and Incorporations by Reference – Visibility ARM 17.8.701- 702 Permit, Construction, and Operation of Air Contaminant Sources - Definitions and Incorporations by Reference ARM 17.8.1701 - 1703 Permit Requirements for Major Stationary Sources or Modification Located Within Nonattainment Areas - Definitions, Incorporations by Reference, When Permit Required ARM 17.8.1001- 1004 Preconstruction Permit Requirements or Major Stationary Modifications Located within Attainment - Definitions and Incorporations by Reference or Unclassified Areas	These are rules that consist of either a statement of purpose, applicability statement, regulatory definitions or a statement of incorporation by reference. These types of rules do not have specific requirements associated with them.

Applicable Requirement	Reason for Not Including
ARM 17.8.1108 - 1109 Visibility Impact Assessment Notification of Land Manager and Adverse Impact and Federal Land Manager- ARM 17.8.704 Permit, Construction, and of Operation Air Contaminant Sources - General Procedures for Air Quality Preconstruction Permitting ARM 17.8.707 Permit, Construction, and Operation of Air Contaminant Sources – Waivers ARM 17.8.730- 732 Permit, Construction, and Operation of Air Contaminant Sources -Denial of Permit, Duration of Permit, and - Revocation of Permit	Although these rules contain requirements for the regulatory authorities and not major sources, these rules can be used as authority to impose specific requirements on a major source.

SECTION V. FUTURE PERMIT CONSIDERATIONS

A. MACT Standards

As of this date (January 18, 2000), the Department is unaware of any future requirement that may be promulgated during the permit term for which this facility must comply other than Industrial Boiler MACT Standard, which is scheduled to be promulgated on 11/15/00.

B. NESHAP Standards

As of this date (January 18, 2000), the Department is unaware of any future requirement that may be promulgated during the permit term for which this facility must comply other than Subpart M for Asbestos.

C. NSPS Standards

As of this date (Janaury 18, 2000), the Department is unaware of any NSPS Standards that are applicable to the facility other than 40 CFR 60, Subpart Da for the (CFBC) Boilers, 40 CFR 60, Subpart Kb for the Car Slurry Oil Tank, and 40 CFR 60, Subpart OOO for limestone crushing.

D. Risk Management Plan

As of this date (September 29, 1999), this facility does not exceed the minimum threshold quantities for any regulated substance listed in 40 CFR 68.115 for any facility process. Consequently, this facility was not required to submit a Risk Management Plan.

If a facility has more than a threshold quantity of a regulated substance in a process, the facility must comply with 40 CFR 68 requirements no later than June 21, 1999; three years after the date on which a regulated substance is first listed under 40 CFR 68.130; or the date on that a regulated substance is first present in more than a threshold quantity in a process, whichever is later.