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FINAL
ENVIRONMENTAL INFORMATION VOLUME
PUBLIC SERVICE COMPANY OF COLORADO
INTEGRATED DRY NO_x/SO_2 EMISSION CONTROL
SYSTEM PROJECT AT ARAPAHOE STATION
DENVER, COLORADO

Prepared for:

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APCD	Air Pollution Control Division
AQCR	Air Quality Control Region
B&W	Babcock and Wilcox
CCT	Clean Coal Technology
CDH	Colorado Department of Health
CFR	Code of Federal Regulations
cfs	cubic feet per second
CO	carbon monoxide
DOE	Department of Energy
EHSS	environmental, health, safety, and socioeconomic
EIV	Environmental Information Volume
EMP	Environmental Monitoring Plan
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
FEMA	Federal Emergency Management Agency
FFDC	fabric-filter dust collector
FIRM	Flood Insurance Rate Map
gpm	gallons per minute
MCP	Materials Containment Plan
mgd	million gallons per day
MSL	mean sea level
MW	megawatt
NAAQS	National ambient air quality standards
NEPA	National Environmental Policy Act
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_x	nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
OSHA	Occupational Safety and Health Administration
PM	particulate matter
PSCC	Public Service Company of Colorado
PSD	Prevention of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
SCR	Selective catalytic reduction
SO_2	sulfur dioxide
SPCC	Spill Prevention, Control, and Countermeasure
tpy	tons per year
USACE	United States Army Corps of Engineers
USEPA	United States Environmental Protection Agency
VOC	volatile organic compound

1.0 INTRODUCTION

This section (1) provides a backdrop to implementation of the project; (2) describes the organization of this report; and (3) summarizes potential environmental, health, safety, and socioeconomic impacts of the project.

1.1 Background

The U.S. Department of Energy (DOE) issued a Program Opportunity Notice in 1989 to solicit proposals for financial assistance required to conduct additional demonstrations of cost-shared Clean Coal Technology projects (CCT-III). The primary objective of the CCT-III program is to fund projects that have the potential for demonstrating cost-effective, commercialization-capable technologies that can achieve significant reductions in sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from coal-burning electric power plants.

One of the projects selected for entitlement to CCT-III funding is the integrated dry NO_x/SO_2 emission control system project at Unit 4 of the Arapahoe Steam-Electric Generating Station in Denver, Colorado. The project is offered for demonstration by Public Service Company of Colorado (PSCC), an investor-owned utility. PSCC serves 75 percent of the gas and electrical needs of Colorado. Its service area extends from Grand Junction, CO on the west to Sterling, CO on the east and from Cheyenne, WY on the north to Alamosa, CO on the south. PSCC has been an independent corporate entity since 1943, and presently has twenty electric generating plants, seven of which are steam-electric plants.

This document is a self-contained Environmental Information Volume (EIV) for the integrated dry NO_x/SO_2 emission control system project that has been prepared by Radian Corporation on behalf of PSCC for submittal to the DOE to facilitate the agency's compliance with the National Environmental Policy Act of 1969 (NEPA). This document was prepared in accordance with the Council on Environmental Quality's NEPA regulations at 40 CFR Parts 1500-1508; the

DOE's guidelines for compliance with NEPA (initially published in the Federal Register on March 28, 1980, and amended in 1982, 1983, and 1987) and the two-volume DOE draft NEPA Compliance Guide (October 1988 reprint) prepared by the Office of NEPA Project Assistance; the CCT-III Program Opportunity Notice; and the Environmental Guidance Manual for Clean Coal Technology III Program Participants, DOE Pittsburgh Energy Technology Center (January 1990).

This EIV is organized as follows: Section 1 is the introduction; Section 2 describes the integrated dry NO_x/SO_2 emission control system project; Section 3 describes environmental, health, safety, and socioeconomic aspects of the existing power plant; impacts of the project on these areas are identified and evaluated in Section 4; Section 5 discusses the federal, state, and local regulatory implications of conducting the demonstration project; Section 6 presents the qualifications of the individuals who prepared this document. Section 7 is a compilation of references and regulatory agency contacts.

1.2 Summary of Impacts

The positive effects of implementing the integrated dry NO_x/SO_2 emission control system at Unit 4 of PSCC's Arapahoe Station include an estimated 70 percent decrease in SO_2 emissions during the highest SO_2 reduction period (sodium injection with urea injection) and an estimated 70 percent decrease in NO_x emissions during the highest NO_x reduction period (low-NO_x burners with urea injection). No increase in particulate matter emissions is anticipated. Carbon monoxide emissions may increase as a result of implementation of the low-NO_x controls, but the optimization of the NO_x controls will be constrained to limit any increase in carbon monoxide emissions to below 100 tons per year for regulatory purposes. Low rates of ammonia may be emitted from the Unit 4 stack as a result of utilization of the urea injection system. Nitrogen dioxide emissions may increase during the sodium injection phase, but the potential associated plume coloration impacts, if any, are expected to be below the state opacity limit.

There should be no demonstrable impact on the local economy, since there will be no new hiring during the construction and operation phases. Existing PSCC and contractor employees will be used.

The project units will affect an area of less than one-third acre on existing Arapahoe Station land adjacent to Unit 4. This area is primarily situated within the former site of an Electric Power Research Institute test facility that still features a foundation overlying a paved area, although most of the previous test facility equipment has been removed. The storage area for the high-sulfur coal that will be used during a limited test phase will encompass approximately 1.5 acres adjacent to the existing coal storage area.

Existing resource requirements, such as fuel, water, and electrical power, will remain the same or will only slightly increase as a result of the project. New resource requirements will be the reagents (sodium, calcium), urea, and urea additives. PSCC has identified potential suppliers of these project resources.

The volume and characteristics of the Unit 4 fly ash stream will be affected by the reagent injection demonstration. The total quantity of solid wastes (fly ash and bottom ash) from Unit 4 is expected to increase from a baseline of 26,000 tons per year to 34,000 tons per year. During sodium reagent injection, the fly ash stream will contain soluble sodium species. The Unit 4 fly ash stream will be segregated from the current on-site ash sluicing and disposal system during the demonstration project. It will be stored dry on site and transported off site for disposal at either a third-party or PSCC land disposal facility which is sited, designed, constructed, permitted, and operated in accordance with the Colorado solid waste facility management rules.

2.0 THE PROPOSED ACTION AND ITS ALTERNATIVES

This section provides (1) an orientation to the plant's current operations; (2) a description of each of the technologies that will be demonstrated during the project and how they will be implemented at the Arapahoe Station; (3) a summary of project resource requirements and environmental effects; and (4) an assessment of PSCC's basis for selecting the site.

2.1 The Proposed Action

PSCC proposes to install an integrated flue gas emission control system to reduce NO_x and SO_2 emissions from a pulverized coal/natural gas boiler that burns low-sulfur coal. NO_x emissions will be reduced through a combination of burner replacement (use of low-NO_x burners), utilization of additional combustion air staging ports to be installed in the furnace walls, and a urea furnace injection system. SO_2 emissions will be reduced using dry sodium- or calcium-based reagent injection systems in combination with humidification. PSCC generally expects to achieve up to 70 percent reductions in NO_x/SO_2 emissions from Unit 4 flue gas. Actual reductions in NO_x/SO_2 emissions will vary, however, throughout the demonstration project as each control technology is studied individually and in combination with the other control technologies. During a very brief period of the demonstration project (30 days), a high-sulfur coal will be burned during utilization of either the dry sodium or the dry calcium injection system. The increased sulfur content of this coal will likely result in a net increase in SO_2 emissions relative to Unit 4's baseline emissions during this 30-day period despite the expected SO_2 removal efficiencies. However, even when taking this emission increase into account, the overall project will result in a net reduction of SO_2 emissions from Unit 4. Although Unit 4 also has the capability to burn natural gas, no natural gas firing periods are planned during the demonstration period.

PSCC's emission control project will be implemented at Unit 4, a 100 megawatt (MW), top-fired boiler at the Arapahoe Station. The project (design, construction, startup, and operation) will span an approximate four-year period. Depending on the outcome of the operational tests, some of the equipment may be left in place at the conclusion of the project or may be removed. However, if the low-NO_x burners and combustion air staging ports achieve the desired level of performance, they will be left in place.

2.1.1 Site Description

2.1.1.1 Site Location

The demonstration project will be undertaken at the Arapahoe Station, an existing power plant operated by PSCC. The plant site consists of 79.92 acres located within the City of Denver in Denver County, adjacent to the South Platte River (see Figure 2-1). The plant address is 2601 South Platte River Drive. Primary access to the site from downtown Denver is via Interstate Highway 25 South to Santa Fe Drive (U.S. Highway 85) to South Platte River Drive. Map coordinates are 39°40'12" N Latitude and 105°00'19" W Longitude.

The plant is located in an urban setting within the corporate limits of Denver. The surrounding area includes residential, commercial, and light industrial land use. Adjacent industrial facilities consist of a municipal sewage treatment plant and a brick manufacturing facility.

2.1.1.2 Existing Plant Operation

PSCC employs approximately 53 people at the Arapahoe Station. There are four generating units in operation, all of which utilize boilers manufactured by Babcock and Wilcox (B&W). The generators for Units 1, 3, and 4 were manufactured by General Electric, while the generator for Unit 2 was manufactured by Westinghouse. The entire plant has a total nameplate capacity of 232 MW. Figure 2-2 presents a general site arrangement and the location of the proposed demonstration unit area and high-sulfur coal storage area.

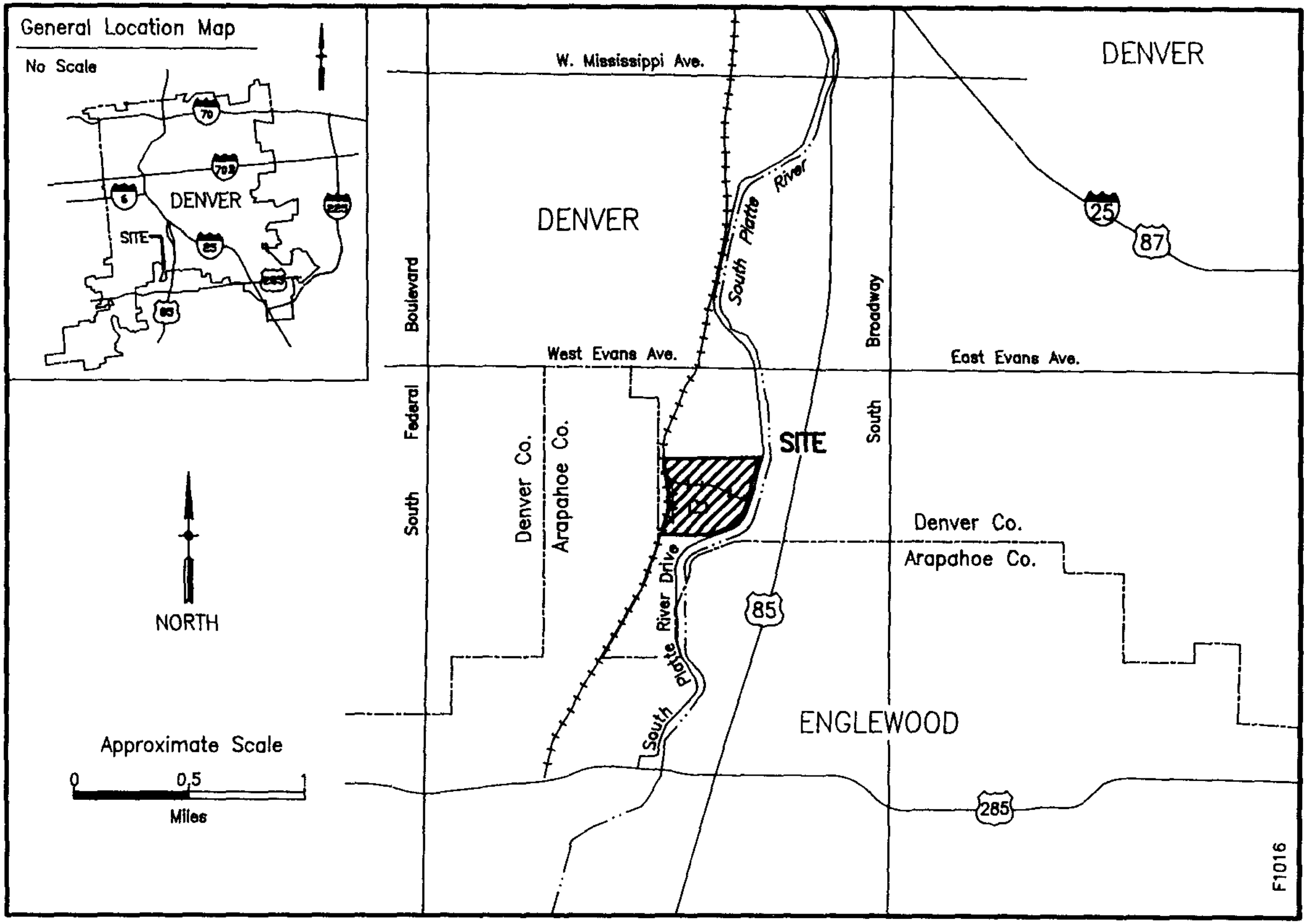


Figure 2-1. General Location Map

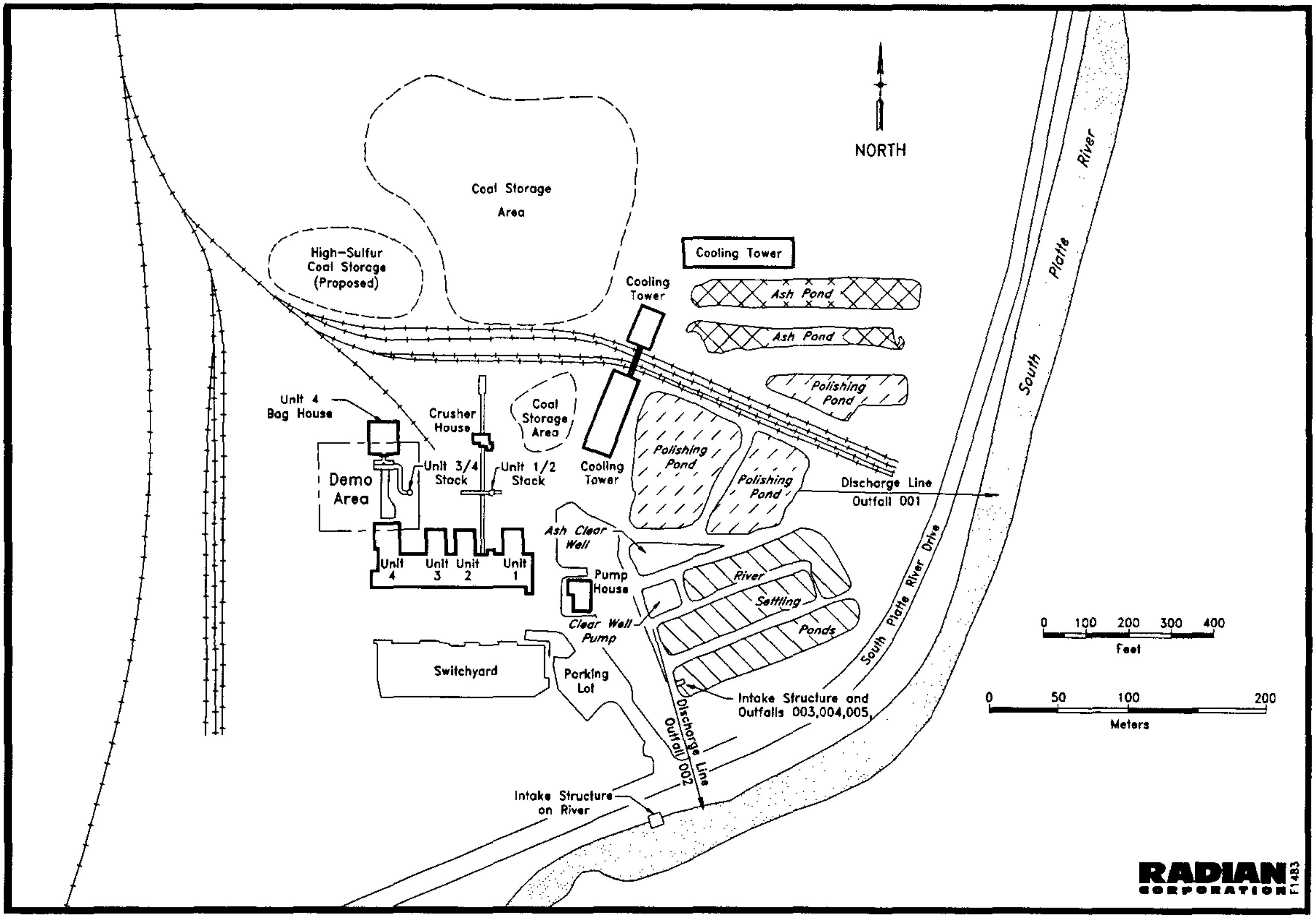


Figure 2-2. Arapahoe Station, General Site Arrangement

Units 1 through 3 are 48 MW top-fired boilers; Unit 4 (the demonstration unit for the project) is a 100 MW top-fired boiler. Unit 1 was placed in service in 1950, Units 2 and 3 in 1951, and Unit 4 in 1955. Each unit has the capability to fire both coal and natural gas. Particulate matter (PM) emissions are controlled by electrostatic precipitators (ESPs) on Units 1 and 2, and by fabric-filter dust collectors (FFDCs) on Units 3 and 4. The FFDC for Unit 4 was installed in 1985 and was manufactured by Ecolaire. Total ash generation (bottom and fly combined) in 1989 was 41,598 tons. Although the volume of ash generation is dependent on plant operations, the ash generation rate for 1990 is expected to be equivalent to that of 1989. There are two stacks for exhaust gases from the units, both 250 feet high and 14 feet across the top. Units 1 and 2 exhaust from one stack, while Units 3 and 4 exhaust from the other.

PSCC burns coal supplied from Colorado and Wyoming. The coal sulfur content averages 0.4 percent. The primary coals being burned at the Arapahoe station are Cyprus Yampa Valley Coal and Empire Energy Coal from Colorado. Table 2-1 provides a compositional analysis of these two coals. Coal is primarily supplied by rail (the Denver and Rio Grande Western Railway); however, it is also trucked in from the PSCC Cherokee plant in Denver when rail costs are prohibitive. Natural gas is primarily supplied by Western Gas Processors, Limited, with Colorado Interstate Gas Company as a backup source.

The Arapahoe Station's coal storage ranges from 150,000 to 200,000 tons. The fuel consumption for 1989 for the entire facility was approximately 527,000 tons, of which the consumption for Unit 4 was approximately 289,000 tons. Coal is pulverized on site by mills located adjacent to each of the four boilers. Rotary coal feeders provide volumetric feed control of coal to each attrition pulverizer, or mill, in service.

TABLE 2-1. COAL COMPOSITION

Parameter	Cyprus Yampa Valley As Burned	Cyprus Yampa Valley Dry Basis[a]	Empire Energy As Burned	Empire Energy Dry Basis[a]
Moisture (%)	10.6	--	13.2	--
Ash (%)	9.6	10.7	8.0	9.2
Fixed Carbon (%)	45.4	50.7	45.0	51.9
Volatiles (%)	34.1	38.1	33.8	38.9
Sulfur (%)	0.4	0.4	0.4	0.4
Btu Content (Btu/lb)	13,903	15,500	10,600	12,200
Carbon (%)	62.8	70.2	61.5	70.8
Hydrogen (%)	4.5	5.0	4.5	5.1
Nitrogen (%)	1.6	1.8	1.3	1.5
Oxygen (%)	10.5	11.7	11.1	13.0

Source: PSCC, Fuels Division.

[a]Calculated from "as received" analysis.

PSCC is contractually authorized by the City of Denver to divert 1 to 5 cubic feet per second (cfs) of South Platte River water, or up to 4,000 acre-feet of water annually. The plant's average annual water withdrawal volumes from the river for the past 15 years are:

1975 - 3,003 acre-feet (2.7 mgd)	1983 - 997 acre-feet (.89 mgd)
1976 - 2,879 acre-feet (2.57 mgd)	1984 - 1,310 acre-feet (1.17 mgd)
1977 - 2,916 acre-feet (2.6 mgd)	1985 - 1,273 acre-feet (1.137 mgd)
1978 - 2,533 acre-feet (2.26 mgd)	1986 - 1,064 acre-feet (0.95 mgd)
1979 - 3,230 acre-feet (2.88 mgd)	1987 - 1,241 acre feet (1.107 mgd)
1980 - 2,900 acre-feet (2.59 mgd)	1988 - 1,222 acre-feet (1.091 mgd)
1981 - 2,039 acre-feet (1.82 mgd)	1989 - 1,800 acre-feet (1.607 mgd)
1982 - 1,600 acre-feet (1.43 mgd)	

As indicated by this data, Arapahoe Station's 1989 river water consumption volume was 1,800 acre-feet [1.6 million gallons per day (mgd)] (mostly cooling water and ash sluice use). There is, therefore, a considerable amount of water available to PSCC under its contractual rights. Water is diverted from the river using two pumps which are located across the street from and south of the plant. City water is also purchased for use in general plant operations and for potable water. Approximate consumption in 1989 of treated city (tap) water was 145 acre-feet.

Figure 2-3 depicts wastewater (process and storm water) management on site. The Arapahoe Station currently operates under a wastewater discharge permit (Permit No. CO-0001091) issued by the Colorado Department of Health, Water Quality Control Division, that authorizes the following outfalls:

1. Outfall 001--ash polishing pond and emergency ash pond discharge;

2. Outfall 002--emergency bypass for Outfall 001;

3. Outfall 003--backflush of river water in winter to prevent icing of intake;

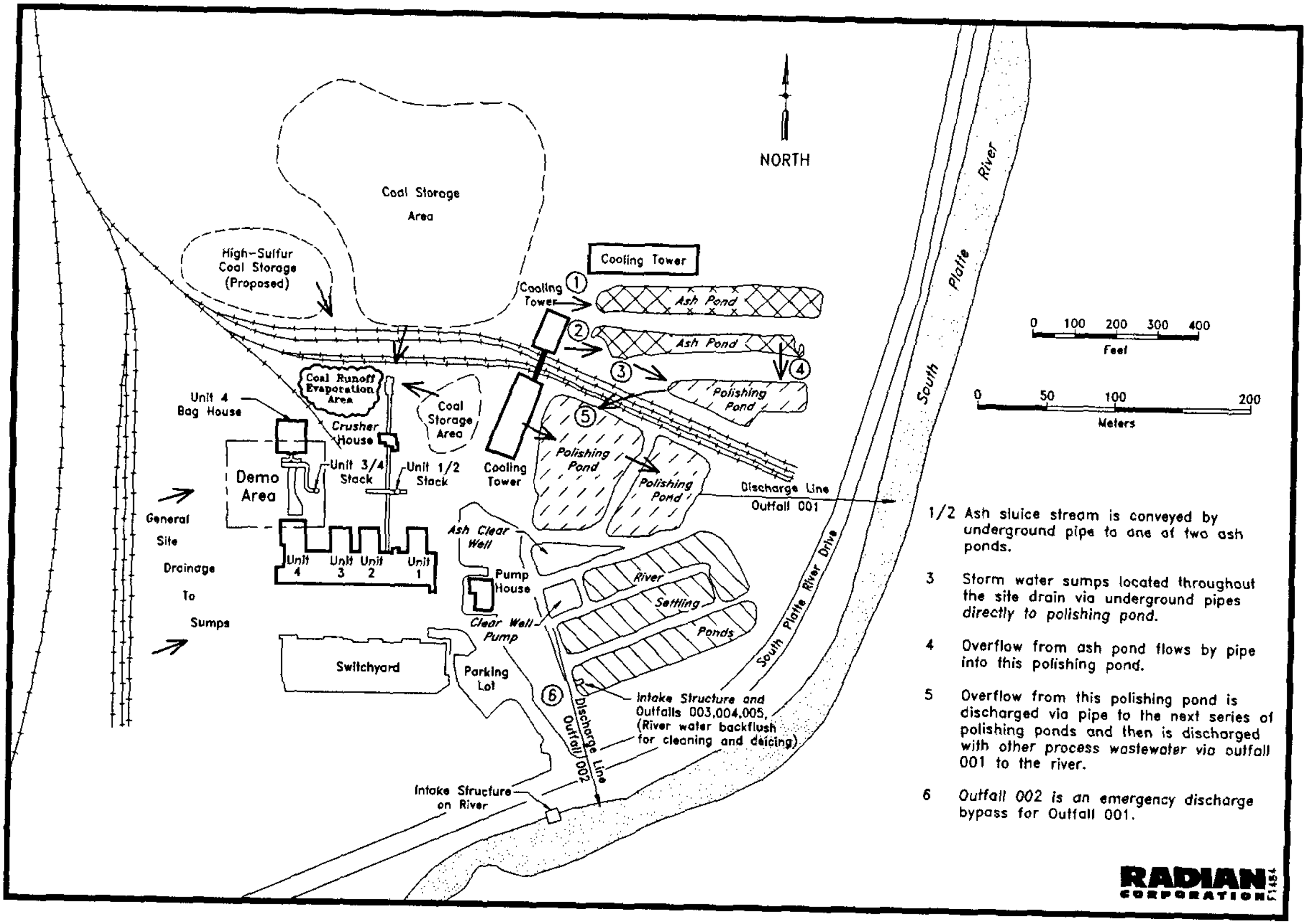


Figure 2-3. Arapahoe Station, Wastewater Management

4. Outfall 004--backflush of river water used to keep debris away from intake pumps; and

5. Outfall 005--backflush of river water used to clean the intake screen.

Outfall 001 is the process wastewater discharge point and includes boiler blowdown, evaporator wastewater, zeolite softeners wastewater, plant and yard drains, and the service water system (ash transport water and cooling tower blowdown). This outfall, located at the outlet of the final polishing pond, is a pipe which discharges to the South Platte River. The average discharge volume from Outfall 001 (based on data from 1989) is 300,000 gallons per day (gpd). Daily and weekly monitoring of flow, total suspended solids, oil and grease, pH, temperature, and residual chlorine are required for Outfall 001 by the state permit. Outfall 002 (an emergency bypass for Outfall 001) and Outfalls 003, 004, and 005, which consist solely of river water discharge, normally show no significant discharge. Sanitary wastewater (approximately 11,000 gpd) is discharged to the city sanitary sewer.

With respect to the ash sluice system, for each generating unit, river water is pumped through jet eductors to create a vacuum. This vacuum is used to draw bottom ash and fly ash from collection hoppers near the boilers and under the particulate control devices, respectively. The ash becomes mixed with the river water, and the resulting slurry is pumped to one of two large ash ponds located north of the railroad tracks. In each pond, the solids settle to the bottom, and water is withdrawn from the upper level of the pond to a second pond. In the second pond, additional solids settling occurs, and the nearly solids-free water ultimately flows to the final polishing pond. From the polishing pond, the water is discharged via Outfall 001 in accordance with the effluent limits established in Permit No. CO-0001091.

When one of the ash ponds becomes nearly filled with settled solids, the sluice stream flow is diverted to the other empty pond. The filled pond is decanted, and allowed to dry by evaporation. When sufficiently dried (normally when the solids moisture level is reduced to about 20 weight percent), the solids are dredged out of the pond into trucks for off-site disposal at a state-authorized facility. When completely dredged out, the pond is ready to put back in service as either a primary or secondary settling pond.

With respect to storm water, the plant yard is graded such that all precipitation which falls upon the site is contained within the site. The yard is graded such that storm water drains to sumps located throughout the yard; underground pipes convey this water to a polishing pond located north of the railroad track. As part of the discharge permit issued by the Colorado Water Quality Control Division, the Arapahoe Station has prepared a Materials Containment Plan (MCP) [which incorporates a Spill Prevention Control and Countermeasure Plan (SPCC)] for chemicals and oils used at the site. The MCP/SPCC plan provides for immediate containment of a spill by use of available spill control materials. If a spill is not timely contained, it will drain into the stormwater system. However, Outfall 001 (ultimate discharge to the river) can be shut off so that any spills are contained within the ponds.

2.1.2 Engineering Description of the Proposed Action

The demonstration project will achieve reductions in the emissions of NO_x and SO_2 through a combination of combustion modifications and post-combustion controls. The modifications will be made on Unit 4; the key design features of Unit 4 are summarized in Table 2-2. Figure 2-4 is a conceptual design schematic of the project, while Figure 2-5 presents a plot plan of the demonstration project at the plant site.

2.1.2.1 Description of Project Phases

The integrated dry NO_x/SO_2 emission control system project at Arapahoe Unit 4 will be accomplished in three phases: Phase I--Design; Phase II--Construction and Startup; and Phase III--Operation and Testing. Figure 2-6 depicts the most recent overall schedule for the project. The overall schedule of activities includes engineering, procurement, construction,

TABLE 2-2. UNIT 4 DESIGN PARAMETERS

Type:	Steam Turbine
Name and Plate Rate:	100 MW
Primary Fuel:	Coal
Alternate Fuel:	Gas
Operation Date:	1955
Boiler Manufacturer:	Babcock & Wilcox
Boiler Type:	Top-Fired
Steam Flow:	930,000 lb/hr
Steam Temperatures:	1,000°F
Design Pressure:	1,600 psig
Existing Burners:	12 top-fired burner tips mounted on roof (12 tips each for pulverized coal and natural gas fuels)
Particulate Control:	Ecolaire fabric filter dust collector designed for 0.007 gr/dscf outlet dust for 600,000 ACFM flue gas at 290°F.

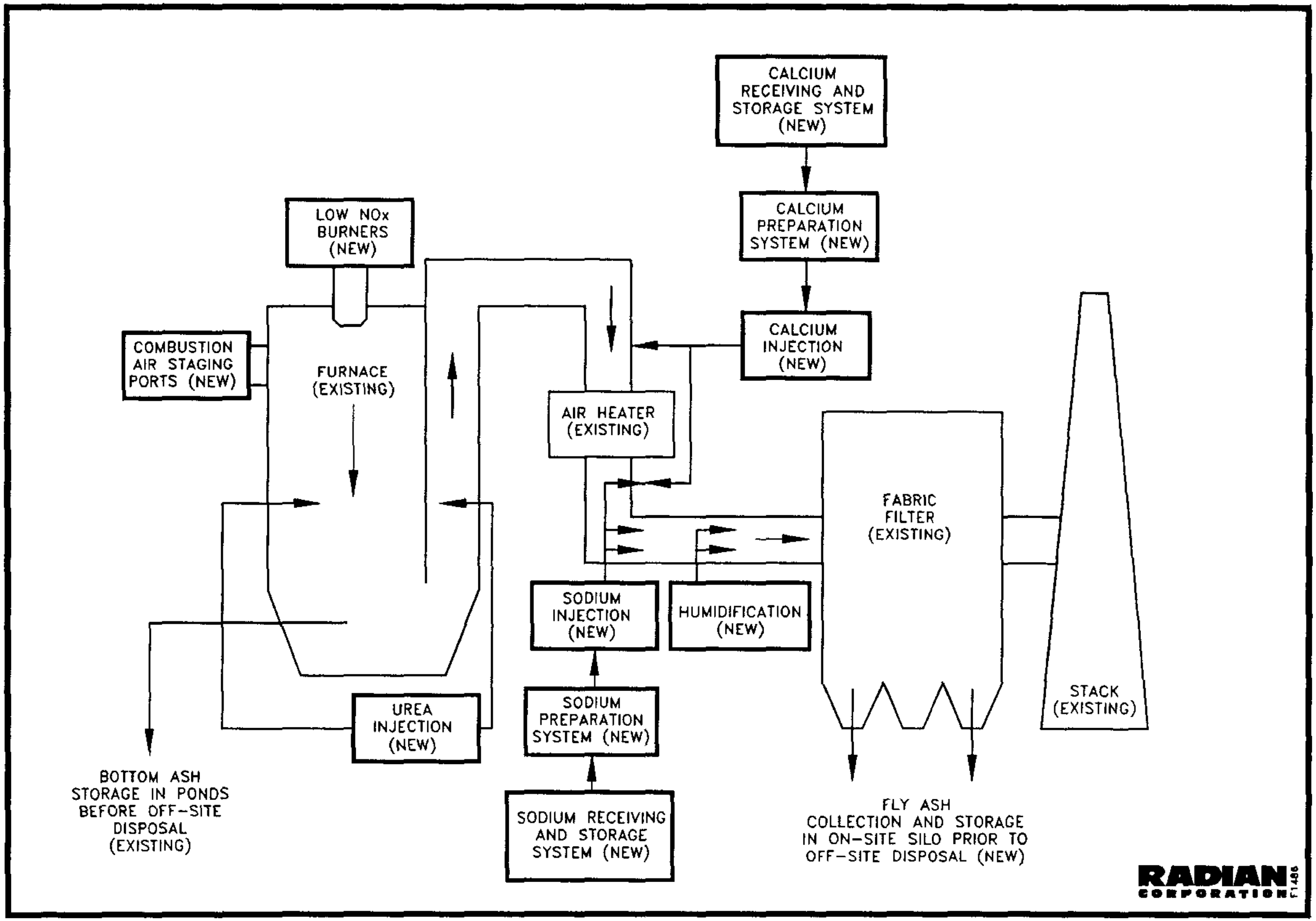


Figure 2-4. Conceptual Design Schematic

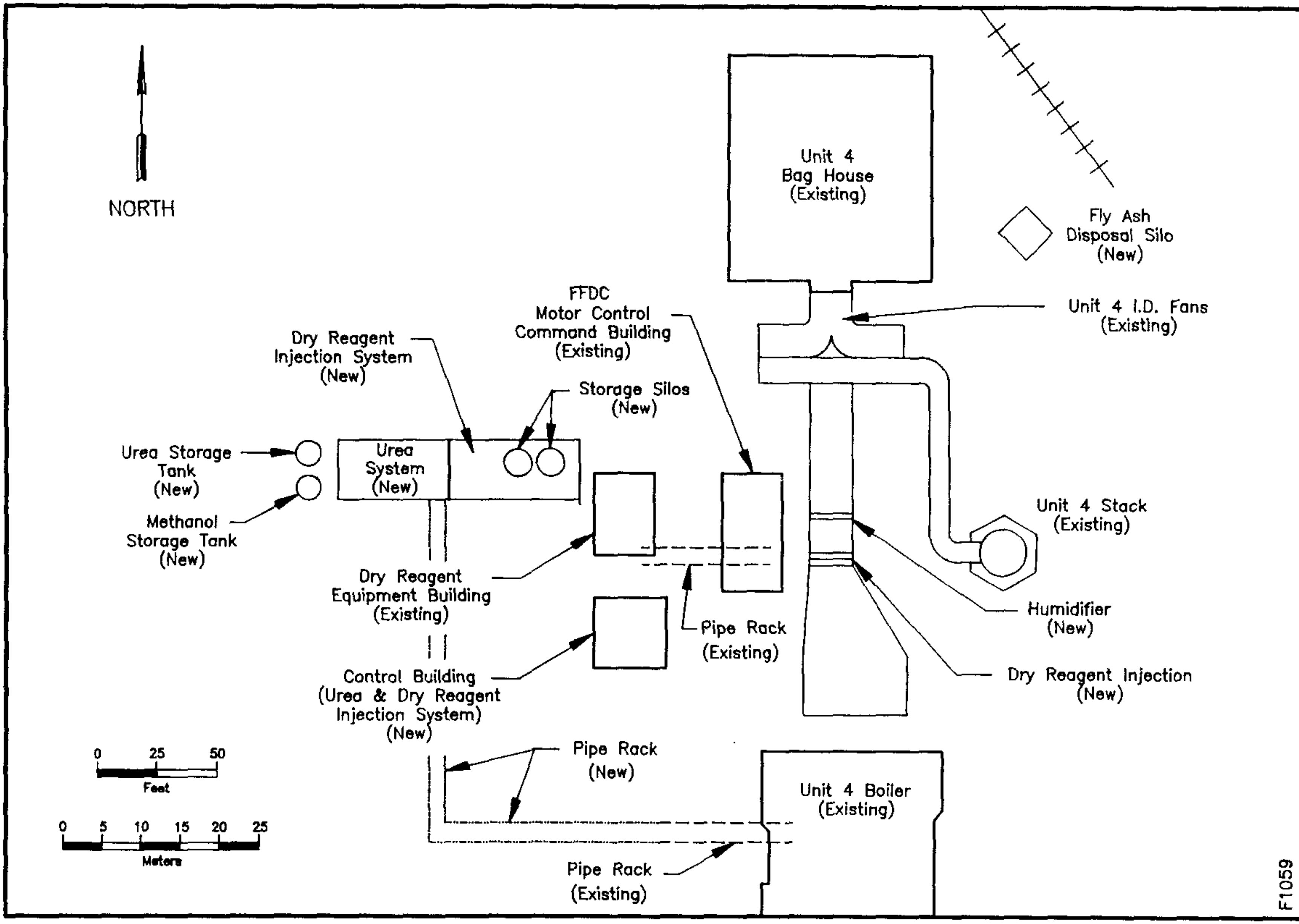


Figure 2-5. Proposed Plot Plan, Demonstration Project

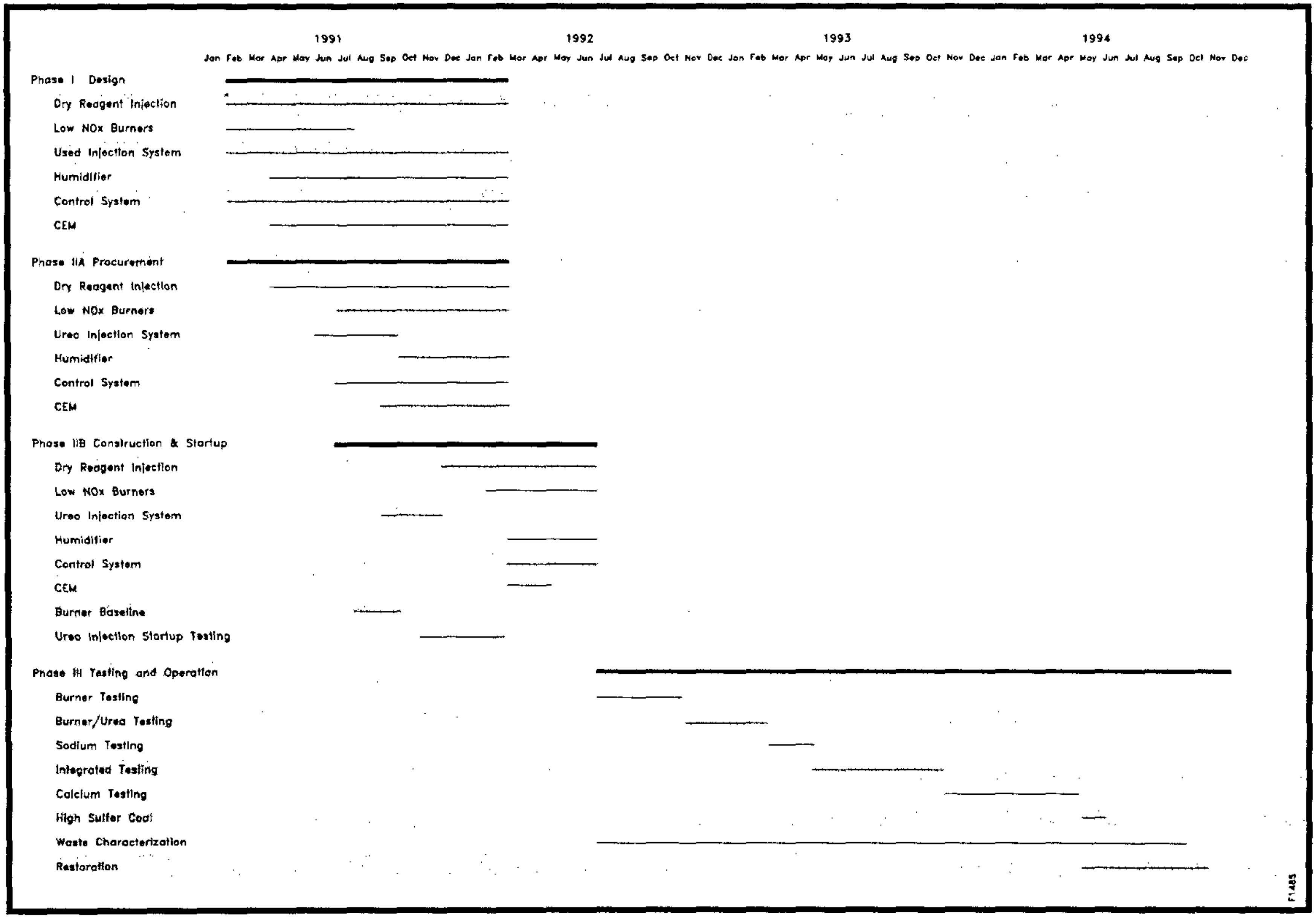


Figure 2-6. Integrated Dry NO_x/SO_2 Emission Control System Project Schedule

testing, waste characterization studies, and, if needed, decommissioning of the project.

Phase I of the demonstration project will involve design of the major equipment components needed for the dry reagent injection system, the fly ash system, the distributed control system, and the testing system. The engineering of these systems and the urea injection and burner systems will also be completed during the first phase. Phase I is expected to last approximately 13 months.

Phase II (procurement, construction, and startup) includes utility relocation (air, water, steam), demolition of foundations (if needed), platform and additional foundation (if needed) construction, installation of mechanical equipment and electrical/instrumentation and controls, and asbestos removal. The construction of the NO_x removal system includes the removal and replacement of existing burners, boiler modifications, the addition of a urea injection system, the upgrade of the control system and instrumentation, and all civil, mechanical, electrical engineering. The SO_2 removal system will involve the installation of the humidifier and dry reagent injection system. Duration of this phase is expected to be 17 months.

Phase III, which includes operation and testing of all of the proposed systems, is expected to last approximately 31 months. This phase is sub-divided into seven testing periods (and also includes waste characterization and restoration activities), as described below:

- Baseline Testing--with no associated emissions reductions, to determine emissions at the current condition of the boiler.

- Urea Injection--to determine the effectiveness of urea injection for NO_x control with the existing burner configuration.

- Low-NO_x Burners--to determine the effectiveness of a low-NO_x burner retrofit, with and without the use of combustion air staging ports, in reducing boiler NO_x emissions.

- Low-NO_x Burners/Urea Injection--to evaluate the combined effectiveness of two NO_x control strategies.

- Sodium Injection--the first portion of the test program to achieve a reduction in SO_2 emissions. All testing is to be conducted during low-NO_x burner operation, while the latter portion will include urea injection for further NO_x control as well.

- Calcium Injection--including both economizer injection and duct injection of lime for SO_2 control.

- High-Sulfur Coal--an anticipated 30-day period of testing to evaluate the effectiveness of low-NO_x burners, combustion air staging ports, urea injection, and the more effective of economizer calcium injection or duct calcium injection, at controlling NO_x and SO_2 emissions from a high-sulfur coal-fired plant.

Depending upon the analysis of the test results at the conclusion of the project, PSCC may decommission the demonstration project test equipment or may leave some or all of it in place. If the low-NO_x burners and combustion air staging ports achieve the desired level of performance, they will be left in place.

2.1.2.2 Description of NO_x/SO_2 Control Technologies

This section provides an overview description of the NO_x/SO_2 control technologies that will be implemented at Arapahoe Station during the demonstration project. Figure 2-4 (previously provided on pg. 2-12) is an integrated design schematic which depicts these technologies.

Low-NO_x Burners

NO_x is formed during pulverized coal combustion by several mechanisms. One significant contributor to NO_x emissions during coal combustion is "thermal NO_x," formed by the dissociation and oxidation of nitrogen in the combustion air primarily at flame temperatures above 2800°F. The predominant source of NO_x emissions from pulverized coal combustion, however, is "fuel NO_x," formed by the decomposition of fuel-bound nitrogen and subsequent reaction with oxygen in the combustion air.

The type of low-NO_x burner to be installed as part of this demonstration, the B&W XCL burner, reduces both fuel and thermal NO_x generation through a combination of air and fuel staging. This staging is accomplished by altering the fuel injection and air flow patterns produced by the burner design. Air staging involves limiting the amount of air available for combustion as the fuel leaving the burner is initially volatilized. By limiting the amount of air available to sub-stoichiometric levels, the fuel-bound nitrogen is less likely to be oxidized to form NO_x. By adding more air later, combustion can be completed at conditions less conducive to NO_x formation. Fuel staging involves the introduction of fuel downstream of the flame under fuel-rich conditions. This mechanism creates hydrocarbon radicals that can attack and destroy a portion of the NO_x. Furthermore, air and fuel staging tend to limit peak flame temperatures, reducing tendencies for thermal NO_x formation.

As the amount of air and fuel staging is increased as a means of lowering NO_x emissions, the production of carbon monoxide (CO) and carbon carryover from the burners may increase, indicating that the combustion process is not efficiently completed. The ability to lower NO_x emissions through air and fuel staging may be practically limited, therefore, by the need to maintain CO emissions and carbon carryover at acceptable regulatory levels.

The XCL burners to be installed as part of this demonstration project also have natural gas elements to provide dual fuel capabilities. The design of these elements achieves air and fuel staging while firing natural gas, also limiting NO_x emissions while firing this fuel. However, no natural gas firing periods are planned as part of this demonstration.

Combustion Air Staging Ports

While the XCL burners that will be installed have inherent air staging capabilities, lower NO_x emissions will result from additional staging of the combustion air. This will be accomplished by adding sub-stoichiometric amounts of air at the burners, then adding the additional amount required to complete combustion through ports that will be installed in the walls of the furnace. In conventional wall-fired boilers, these ports are often called "over-fire air" ports because they are located above the burners, thereby allowing the combustion gases some residence time as they travel upward before the additional air is added. For the top-firing configuration of the Arapahoe Unit 4 boiler, these ports will be physically located below the burners because the combustion gases flow downward rather than upward through the furnace cavity. Using the previous convention, these ports should be called "under-fire air" ports. However, B&W generally calls them "combustion air staging ports," regardless of their position relative to the burners, because they are added as a means of controlling NO_x emissions. Throughout the remainder of this document, the term "combustion air staging ports" will be used to describe the ports that will be installed in the walls of the Unit 4 boiler furnace.

The effectiveness of these ports for NO_x removal is dependent on coal characteristics and furnace design. However, for a given coal and furnace, the effectiveness of the ports is improved as more air is added at the ports rather than at the burners, and as the ports are located further downstream of the burners. As the amount of air added through the ports (rather than the burners) is increased, and as the distance between the burners and the ports is increased, there can be adverse effects on the combustion process. This can lead to increased CO levels and increased carbon carryover in the combustion gas leaving the furnace. Consequently, the amount of air staging and the location of the combustion air staging ports will have to be optimized for this particular coal, burner design, and furnace.

Urea Injection

Further NO_x emission reductions will be achieved through urea injection. The process consists of spraying an aqueous solution of urea into the boiler combustion gases. Urea, nitrogen oxide, and oxygen combine to form nitrogen, carbon dioxide, and water. The process has a reaction temperature range between 1600°F and 2000°F, with an optimum temperature range of 1700°F to 1900°F. At lower temperatures, side reactions can occur which result in the undesirable formation of ammonia (further discussed in Section 4.1.2.2, pg. 4-15), while at higher temperatures the reactions produce additional NO_x.

Two urea injection system manufacturers are under consideration for the project, Nalco/Fuel Tech and BTU Services, Inc. Both use the same basic principle of operation: an aqueous solution of urea is injected into the boiler through a two-fluid atomizer. Compressed air is used as the atomizing medium in both systems. The two vendors utilize different methods for controlling potential ammonia slip through the system. Nalco/Fuel Tech would utilize proprietary chemical additives, while BTU Services would utilize methanol.

Dry Reagent Injection

Removal of SO_2 will be achieved through a dry reagent injection system utilizing sodium or calcium products. The sodium compounds to be tested will most likely consist of sodium bicarbonate, sodium sesquicarbonate, and/or trona (which is an unrefined sodium sesquicarbonate ore). The calcium compound to be used is calcium hydroxide. The reagent will be pneumatically injected into the flue gas and will react with SO_2 to form compounds of sodium or calcium depending on the reagent used. The compounds will collect on the surface of the bags inside the FFDC and, thus, will affect Unit 4's fly ash characteristics.

Flue Gas Humidification

During the calcium injection testing, flue gas humidification will be accomplished by spraying finely atomized water into the flue gas downstream of the air heater and upstream of the FFDC. Evaporation of the water will cause the flue gas to cool, decreasing the volumetric flow rate, and increasing the relative humidity. The increased relative humidity in the flue gas will increase the amount of SO_2 capture by the calcium hydroxide. The more water added (and thus the greater the flue gas relative humidity), the greater SO_2 capture is expected. Flue gas humidification will not be required to promote SO_2 capture during the sodium injection testing, although a portion of the sodium injection testing will likely determine the impacts of humidification.

High-Sulfur Coal Test

The Arapahoe Station currently burns low-sulfur coal (average coal sulfur content is 0.4 percent) from the Cyprus Yampa Valley and Empire Energy mines. As part of the demonstration project, high-sulfur coal (2.51 - 2.75 percent sulfur) will be burned in Unit 4 to test the effectiveness of the control technologies at high-sulfur coal conditions. PSCC has an agreement with Amax Coal Industries, Inc. to supply an Illinois high-sulfur coal, designated as Delta No. 6, for this testing program. Table 2-3 provides a compositional analysis for Delta No. 6. The series of tests should last approximately 30 days.

2.1.2.3 Description of Installation, Operation, and Decommissioning Activities

Construction Phase

The integrated dry NO_x/SO_2 emission control system project will be installed at an existing facility. The project will involve retrofitting the burners and combustion air staging ports and installing the urea, dry

TABLE 2-3. COAL COMPOSITION, DELTA NO. 6

Parameter	As Burned	Dry Basis
Moisture (%)	9.1	--
Ash (%)	10.5	11.5
Fixed Carbon (%)	47.2	52.0
Volatiles (%)	33.2	36.5
Sulfur (%)	2.6	2.9
Btu Content (Btu/lb)	11,664	12,832
Carbon (%)	64.4	70.8
Hydrogen (%)	4.4	4.8
Nitrogen (%)	1.3	1.4
Chlorine (%)	0.12	0.13
Oxygen (%)	7.64	8.42

Source: PSCC, Fuels Division.

reagent, and humidification systems. Modifications to the existing unit which are needed for each system are described below.

Low-NO_x Burners Retrofit. This low-NO_x XCL burner retrofit represents the first U.S. application of low-NO_x burners to a top-fired boiler. Installation of commercial low-NO_x pulverized-coal/gas-fired burners requires alterations to the boiler roof tube panels, secondary air system and windbox, fuel piping, and controls. The twelve burners will also require modification for vertical firing instead of horizontal firing. The modifications are scheduled during a two-month routine outage of Unit 4.

Combustion Air Staging Ports. New ductwork and windboxes will be required for the six combustion air staging ports, in addition to the new assemblies for these ports and associated boiler water wall tube panel modifications to accommodate the combustion air staging port throats. Some alteration of the platforms and stairways will be necessary to accommodate the combustion air staging ports air supply ducts.

Urea Injection. The urea injection system will be mostly contained in an area outside the boiler envelope. Boiler modification will only be required to provide the penetration for the injection atomizers. The Nalco/Fuel Tech system will require the installation of a 57,000-gallon urea storage tank, a 2,000-gallon urea day tank, and a 10,000-gallon (estimated) chemical additive tank. BTU Services' system will require a 36,000-gallon urea storage tank and a 6,000-gallon methanol storage tank. Although the urea systems are not as commercially demonstrated as is the dry reagent injection system, the resource requirements (urea, methanol, chemical additives) are readily available in the commercial market.

Dry Reagent Injection. All of the components of the dry reagent SO_2 removal system have been previously developed and are commercially available. Installation of injection ports in the flue gas duct will be required.

Flue Gas Humidification. An array of atomizers will be installed within existing duct work for the humidification system.

High-Sulfur Coal Test. For the 30-day high-sulfur coal test period, 30,000 tons of Amax Coal Industries, Inc.'s Delta No. 6 coal will be shipped via rail from Illinois and will be stored in a segregated area on site (immediately west of and adjacent to the large coal storage area north of the site's rail line). The coal will be conveyed to the boiler and processed through the Unit 4 pulverizing system in an identical manner to that of the low-sulfur coal.

Operation Phases

The operation and testing phase (Phase III) is estimated to last approximately 31 months. During this period, a large volume of project characterization data will be compiled. These data will be collected during the following test sequences: (1) emissions and ash characterization; (2) boiler performance including carbon carryover, flame carryover, furnace gas exit temperatures, attemperation, heat absorption characteristics, slagging/fouling, and soot-blowing requirements; (3) furnace/convective gas temperature characterization; and (4) burner/overfire air interaction. The test sequences consist of planning, testing, and analyzing each system.

Decommissioning Phase

If some of the integrated flue gas control technology proves economically advantageous and technically feasible, the particular equipment may be left in place at the end of the demonstration period. If other equipment performance proves unsatisfactory, the plant will be returned to its original condition as directed by plant personnel. If the low-NO_x burners and combustion air staging ports achieve the desired level of performance, they will be permanently left in place.

2.1.2.4 Project Source Terms

Project source terms are resource requirements of the project as well as environmental residuals generated by the project; both of these components define the impacts of the project. Project source terms include, but are not limited to: land, labor, and fuel requirements, solid waste production, air emissions, and effluent discharges. When project source terms are applied to the existing environment (characterized in Section 3), the environmental impacts of the project can be identified and quantified (Section 4).

Resource Requirements

Estimated coal requirements during the demonstration project for Unit 4 (from 1989 consumption) are 289,000 tons per year (tpy). This estimate agrees with the expected plant heat input and operating time for the demonstration period. Therefore, the current level of coal usage is not expected to increase as a result of the demonstration project. During the 30-day high-sulfur coal test, approximately 30,000 tons of high-sulfur coal will be fired. This amount will offset consumption of the low-sulfur coal that would otherwise be fired during this period. PSCC has an agreement with Amax Coal Industries, Inc. of Indiana for the supply of this coal.

The urea injection system will require between 484,000 and 2,420,000 gallons of urea per year depending on the particular system which is used and the system operating conditions. If BTU Services is used, 169,000 gallons of methanol per year will also be required for this system. Urea will be obtained from Coastal Chemical, Inc. in Cheyenne, Wyoming. For sodium injection in the dry reagent system, Unit 4 will require approximately 5,000 to 7,000 tpy of sodium reagent, depending on the reagent type used and the operating conditions required to achieve 70 percent SO_2 removal. The sodium reagents to be tested are readily available from the Green River area of Wyoming. If calcium reagent is used in the dry reagent system, between 5,000 and 8,000 tpy of calcium hydroxide will be needed. The flue gas temperature at the point of injection and other operating conditions will influence the amount of calcium hydroxide required to achieve 70 percent SO_2 removal. The National Lime Institute was contacted to determine vendors which could provide this reagent. The closest vendors of high-calcium hydrated lime to the Colorado area include: Pete Lien & Sons in Rapid City, SD, and ChemStar, Inc. in Nelson, AZ.

Water requirements are expected to increase slightly from 1989 water usage as a result of the demonstration project, but this increase is well within historical water consumption patterns. The estimated increase by year as a result of the demonstration program is as follows:

1991	6 acre-feet
1992	12 acre-feet
1993	37 acre-feet
1994	45 acre-feet

PSCC's surface-water rights authorize diversion of up to 4,000 acre-feet per year. The estimated total increase in river water consumption from implementation of the project (100 acre-feet), when added to the 1989 usage of 1,800 acre-feet, remains well below the utility's authorized use. Furthermore, the increased river water usage will remain well below historical river water usage by Arapahoe Station. For example, the data presented in Section 2.1.1.2 (pg. 2-7) indicate that during the period of 1975 through 1989, river water usage by the Arapahoe Station varied from 997 acre-feet/year to 3,230 acre-feet/year. The highest estimated river water consumption by the test program of 45 acre-feet/year (projected for 1994), when added to the latest usage data from 1989, will result in a total projected river water usage of 1,845 acre-feet in the year 1994. This projected usage is still substantially lower than historical use volumes (for example, the volume is lower by nearly 1,400 acre-feet than the previous maximum usage of 3,230 acre-feet in 1979).

In addition to the estimate for river-water consumption, plant potable water use will increase to a total of 154 acre-feet for the 18-month urea injection system test period. This total represents an increase of 9 acre-feet per year, or approximately a six percent increase in the plant's current potable water consumption.

With respect to labor needs, the design, construction, management, environmental, and regulatory compliance work will be accomplished by existing PSCC and contractor employees.

Land requirements include area for the urea injection system, the dry reagent injection system, and storage of the high-sulfur coal. The entire urea system, including tanks, will require an existing area of approximately 25 feet by 70 feet (ft). The dry reagent injection system will require an existing building (approximately 33 ft by 25 ft), a new building (approximately 15 ft by 15 ft), and two silos (each approximately 15 ft in diameter by 33 ft high) on an existing foundation. The dry fly ash storage and unloading silo will occupy an area of about 30 ft. square. The retrofit of the burners will not require additional land space. Scaffolding and platforms will be located in and around the unit. The total area needed for the new units is less than one-third acre and will be located on an existing foundation at Arapahoe Station. The high-sulfur coal storage area will encompass approximately 1.5 acres adjacent to the existing coal storage area

With respect to the Unit 4 fly ash, an off-site landfill will be utilized for disposal of the fly ash from Unit 4. PSCC will either utilize an existing third-party landfill or construct a new one. The determination will be based on compatibility of the ash with existing landfills and feasibility of a PSCC-operated landfill.

Environmental Residuals

As detailed in Section 4.1.2.1, the positive effects of implementing the integrated dry NO_x/SO_2 emission control system at Unit 4 include an estimated 70 percent decrease in SO_2 emissions during the highest SO_2 reduction period (sodium injection with urea injection) and an estimated 70 percent decrease in NO_x emissions during the highest NO_x reduction period (low-NO_x burners with urea injection). No increase in particulate matter emissions is anticipated. Carbon monoxide (CO) emission increases, which may result from implementation of the low-NO_x controls, will not exceed 100 tpy. Small amounts of ammonia may be emitted from the Unit 4 stack during tests of the urea injection system. Nitrogen dioxide emissions will likely increase during the sodium injection phase, but the potential associated plume coloration impacts, if any, are expected to be below the state opacity limit, as discussed in Section 4.1.2.1.

As discussed in Section 4.3.1, the quantity of the Unit 4 fly ash stream will be increased by the sodium and calcium injection demonstration and the characteristics of the fly ash stream will be altered. The total quantity of Unit 4's ash generation is expected to increase from a baseline of 26,000 tpy to approximately 34,000 tpy (increase in fly ash, no increase in bottom ash). Sodium-based fly ash will contain soluble sodium species. The Unit 4 fly ash will be segregated from the current on-site ash sluicing and disposal system during the demonstration project. It will be stored dry on site and transported off site for disposal at either a third-party or PSCC land disposal facility which is sited, designed, constructed, permitted, and operated in accordance with the Colorado solid waste facility management rules.

2.1.2.5 Potential Environmental, Health, Safety, and Socioeconomic (EHSS) Receptors

Environmental, health, safety, and socioeconomic (EHSS) receptors are people, places, and environmental media that could be adversely or positively affected by the project. Examples of potential EHSS receptors for any type of project include: plant and project workers (i.e., occupational safety and health issues); nearby residents (adverse health effects, nuisance factors); area population (jobs, economic stimuli, increased demand for services); distant populations (downwind effect of emission changes); local environment, including statutorily protected or unprotected plants and animals and their habitat; agricultural plants and animals; public recreational areas or scenic values (accessibility and enjoyment); and health effects and nuisance factors affecting adjacent commercial or institutional areas (such as campuses, shopping centers).

Section 4 of this EIV presents a detailed description of anticipated EHSS impacts of the demonstration project. To summarize, based on an evaluation of potential EHSS receptors and on the identification of project source terms (Section 2.1.2.4), the primary issues associated with potential EHSS receptors for this project are:

- Effects on ambient air quality during the 30-day high-sulfur coal test period when SO_2 emissions will increase from baseline emissions of 880 lbs/hr to as much as 2,499 lbs/hr. The overall net SO_2 reduction for the project, however, taking into account the temporary increases during the 30-day test, is 800 tpy.

- Effects on ambient air quality from increased CO levels (from low-NO_x controls) in a nonattainment area. PSCC will, however, operationally restrict the low-NO_x controls such that additional CO emissions do not exceed 100 tpy for regulatory purposes.

- Potential increases in plume opacity during the sodium injection period when NO_2 emissions are expected to increase. The maximum predicted opacity is expected to be below the state regulatory standard.

- An increase in the quantity and a change in the characteristics of the Unit 4 fly ash stream attributable to sodium and calcium reagent injection. An additional 8,000 tpy of Unit 4 fly ash will be generated during the reagent test periods. The fly ash stream produced during the sodium injection period will contain soluble sodium species. The Unit 4 fly ash will be disposed of in an off-site third-party or PSCC landfill that is sited, designed, constructed, permitted, and operated in accordance with Colorado solid waste facility management rules.

These issues are addressed in detail in Sections 4 (Consequences of the Project) and 5 (Regulatory Compliance).

2.2 Alternatives

This section identifies alternatives to implementation of the project and alternative locations that were available to PSCC.

2.2.1 No-Action Alternative

One primary goal of the DOE CCT-III program is to demonstrate the benefits of NO_x/SO_2 emission reductions through the use of innovative technologies on coal-fired boilers. The no-action alternative would preclude a detailed assessment of the promising dry NO_x/SO_2 technologies on top-fired boilers.

2.2.2 Alternative Sites

Alternative locations for the dry NO_x/SO_2 demonstration project are the 20 electric generating stations operated by PSCC in Colorado. Thirteen of these stations are not fossil-fuel steam-electric plants (i.e., they are hydroelectric, diesel, nuclear) and are, therefore, not viable candidate sites. The primary criteria used by PSCC to select a site for the integrated dry NO_x/SO_2 emission control project were: coal-fired boiler with a top-fired configuration, 100 MW size, proximity to Denver corporate offices, and reasonable cost of conversion. Of the seven steam-electric stations that were candidate sites, Arapahoe Station was chosen for a number of economic and technical reasons. The Arapahoe plant is located in Denver, near PSCC's corporate engineering, financial, and regulatory compliance headquarters. Unit 4 is a 100 MW unit, which was determined by PSCC to be large enough to achieve meaningful technical results for a commercial-scale demonstration test, but not too large to render the project cost-prohibitive. From 1977 until the early 1980s, the Electric Power Research Institute (EPRI) operated an emissions control test facility at the Arapahoe Station, next to Unit 4. Since Unit 4 flue gas was utilized during some of the test periods, there was preexisting environmental and operational performance data available for Unit 4, and plant operating personnel are already familiar with operating in a technology-testing environment.

Of the other six PSCC steam-electric plants, the Cherokee Station in Denver was not a candidate site for the dry NO_x/SO_2 technologies because: 1) its Unit 3 (170 MW) is being utilized for a CCT-III demonstration of low-NO_x burners and gas reburning; and 2) its Unit 1 (a 100 MW top-fired boiler) is under a permit requirement to achieve a fixed emission reduction percentage per year. The Cameo Station units were too small (26 and 48 MW). The units at Comanche, Pawnee, and Valmont Stations are tangentially- or wall-fired instead of top-fired, and, therefore, could not be candidates for this particular demonstration project. Zuni Station units are oil- and gas-fired and do not use coal.

3.0 EXISTING ENVIRONMENT

Relevant environmental, socioeconomic, and cultural features of the existing plant site and surrounding area are described in this section.

3.1 Atmospheric Resources

3.1.1 Local Climate

The Denver area is strongly influenced by the Rocky Mountains which lie just west of the city and provide a semi-arid, temperate-continental climate. The mean annual precipitation is 13.8 inches (in.), and average snowfall is 55 to 59 in. The temperature ranges from 29.5°F (January) to 73.3°F (July) with a mean annual temperature of 50.3°F. Annual temperature and precipitation data for Denver are presented in Table 3-1. Clear days (30 percent cloud cover or less) occur 30 to 60 percent of the time, while cloudy days (80 percent or more cloud cover) occur 16 to 36 percent of the time (Ref. 1). A wind rose for Denver, presented in Figure 3-1, illustrates that predominant winds in the area are from a south-southwestern direction.

3.1.2 Ambient Air Quality

The Arapahoe Station is in Air Quality Control Region (AQCR) 3 of Colorado. According to the 1988 Air Quality Data Report by the Air Pollution Control Division of the Colorado Department of Health, this region attains National Ambient Air Quality Standards (NAAQS) for sulfur dioxide, nitrogen oxide, and lead, and is nonattainment for carbon monoxide, particulate matter, and ozone. The Air Pollution Control Division reports that there are 948 air pollution sources in AQCR 3, with 897 active sources in Denver County.

Within AQCR 3, there are 20 separate monitoring stations. There are no on-site ambient air monitoring stations at the Arapahoe plant. To provide a general indication of ambient air quality in the vicinity of the plant, data

TABLE 3-1. AVERAGE DENVER TEMPERATURE AND PRECIPITATION DATA (1951 - 1980)

Month	Average Daily Temperature (°F) Max	Min	Mean	Average Precipitation (Water Equivalent) inches
January	43.1	15.9	29.5	0.51
February	46.9	20.2	33.6	0.69
March	51.2	24.7	38.0	1.21
April	61.0	33.7	47.4	1.81
May	70.7	43.6	57.2	2.47
June	81.6	52.4	67.0	1.58
July	88.0	58.7	73.3	1.93
August	85.8	57.0	71.4	1.53
September	77.5	47.7	62.6	1.23
October	66.8	36.9	51.9	0.98
November	52.4	25.1	38.7	0.82
December	46.1	18.9	32.6	0.55
Year	64.3	36.2	50.3	15.31

Source: Climates of the States. Gale Research Company, Book Tower, Detroit, Michigan, 1985, p. 239.

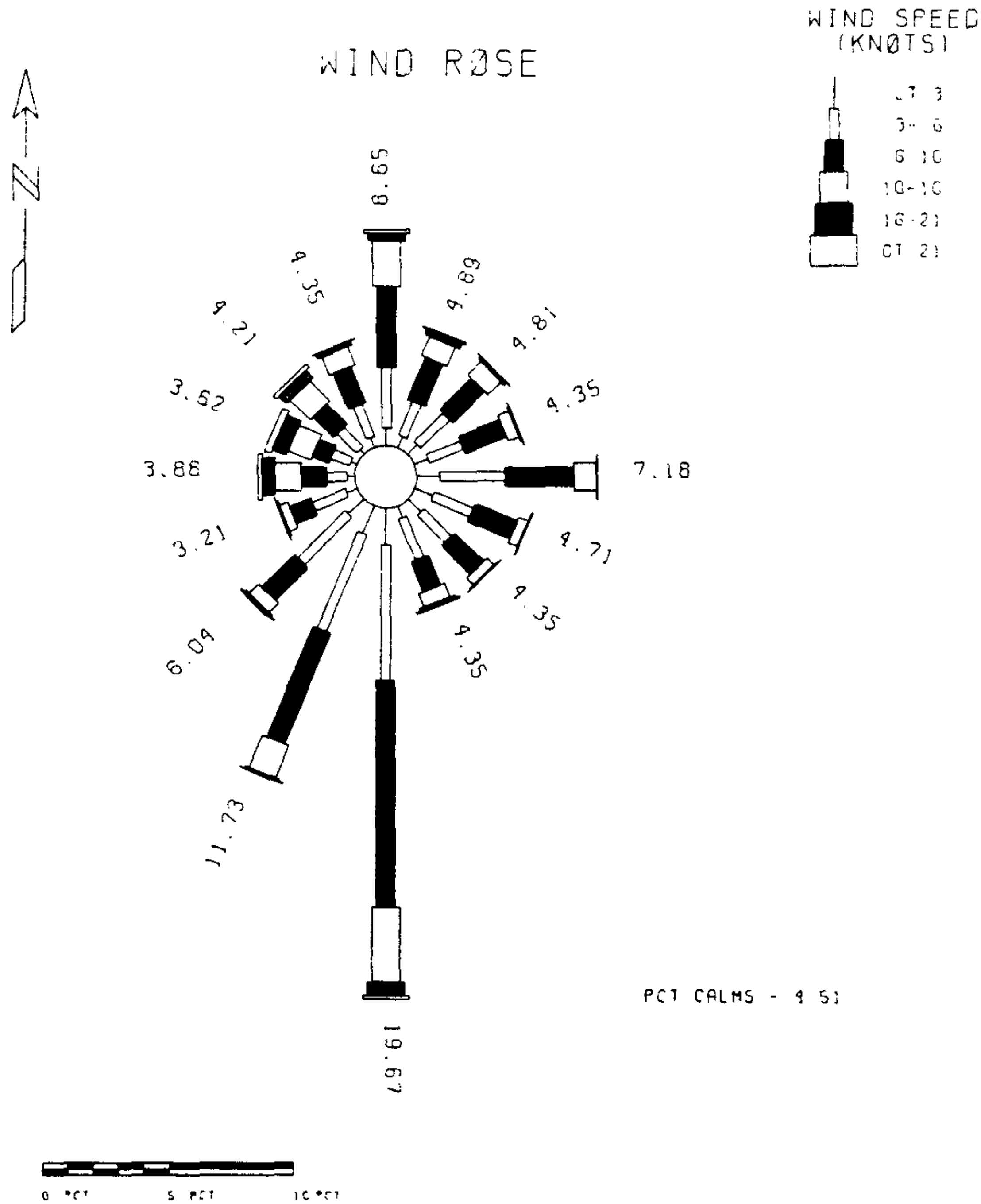


Figure 3-1. Wind Rose for Denver, Colorado (1974-1978)
Source: National Climatic Data Center, Asheville, NC

were composited from three state stations that are closest to the plant and that are subject to the predominant wind patterns for the area (south, southeast, and north). Table 3-2 presents the federal and state primary standards (and associated averaging times) for each of the criteria pollutants. Also, the table shows composite information on the concentrations of the criteria pollutants that were measured at the three stations (Ref. 2). As indicated in the table, not all pollutants were measured at each station.

3.2 Land Resources

3.2.1 Topography

Denver is located near the eastern front of the Southern Rocky Mountains in the Colorado Piedmont section of the Great Plains. The topography is characterized as broadly rolling, with local scarps where there are outcrops of resistant bedrock units. The land slopes from west to east at a gradient of about 10 feet per mile (Ref. 1).

The plant site itself is fairly level. Since the site consists of a disturbed industrial use area, vegetation is limited to grasses and small shrubs. As explained in Section 5.6, most of the plant site is within the 100-year floodplain, as depicted on the relevant Federal Emergency Management Agency Flood Insurance Rate Map. However, a recent profile of the 100-year floodplain in this area by the Denver Urban Drainage and Flood Control District indicates that the area of the demonstration project is above the elevation of the 100-year flood.

3.2.2 Geology

Denver lies near the western edge of the Denver Basin, one of the largest structural basins in the Rocky Mountains. The deepest area of the basin lies below Denver, with more than 13,000 feet of sedimentary rock ranging from Pennsylvanian to Paleocene. To the west of Denver lies the Front Range of the Southern Rocky Mountains. The Front Range is a complexly faulted

TABLE 3-2. FEDERAL AND COLORADO AMBIENT AIR QUALITY STANDARDS (PRIMARY) AND LOCAL MONITORING RESULTS

Pollutant	Averaging Times	Federal & State Standards	MAXIMUM CONCENTRATION[a] Englewood (Huron)[b]	Denver Gates[c]	Denver Camp[d]
Carbon Monoxide	1 hour	35 ppm	13.7	--[e]	50.5
	8 hours	9 ppm	6.5	--[e]	18.7
Ozone	1 hour	0.12 ppm	0.12	--[e]	0.10
Nitrogen Dioxide	Annual	0.053 ppm	0.031	--[e]	--[e]
Sulfur Dioxide	Annual	0.03 ppm	--[e]	--[e]	0.009
	24 hours	0.14 ppm	--[e]	--[e]	0.03
	3 hours	0.50 ppm	--[e]	--[e]	0.07
Particulates (PM10)	Annual	50 $\mu g/m^3$	--[e]	35 $\mu g/m^3$	31 $\mu g/m^3$
	24 hours	150 $\mu g/m^3$	--[e]	68 $\mu g/m^3$	123 $\mu g/m^3$
Lead	Quarterly	1.5 $\mu g/m^3$	--[e]	0.08 $\mu g/m^3$	0.07 $\mu g/m^3$

[a]Source: Colorado Air Quality Data Report, 1988.
State of Colorado Department of Health, Air Pollution Control Division.

[b]Located approximately 1 mile south of Arapahoe Station.

[c]Located approximately 2 miles north of Arapahoe Station.

[d]Located approximately 6 miles north of Arapahoe Station.

[e]No measurements performed by state.

anticlinal arch of Precambrian crystalline rocks. The foothills region consists of steeply dipping Paleozoic and Mesozoic sedimentary rocks which form hogback ridges and gravel-covered pediments. The mountains are separated from the plains by the Golden Fault, a high-angle reverse fault (Ref. 1).

The soil deposits at Arapahoe Station consist of the Post-Pinery Creek alluvium from the Holocene period. These deposits consist mainly of light to dark grayish-brown clay, silt, and small amounts of gravel. Dark brown and dark bluish-black humic bog clays are interbedded in places with sand and silt. Silt along the South Platte River ranges from 5 to 10 feet thick. Permeability of the alluvium is medium to low, particularly in the clay and silt. Compaction of the material is usually easy, and foundation conditions are fair to good (Ref. 3).

3.3 Water Resources

3.3.1 Surface Water

The South Platte River and its tributaries are a major source of water for the Denver area. Flood protection is provided by Chatfield Dam and Reservoir, located approximately ten miles upstream of the Arapahoe plant. Reservoirs used for water supply above the Chatfield Dam include Strontia Springs Reservoir, Cheesman Reservoir, and Eleven Mile Canyon Reservoir.

PSCC discharges wastewater from the Arapahoe Station to Segment 14 of the South Platte River. This segment is classified as Recreation Class 2, Aquatic Life Class 1 Warm Water, Water Supply, and Agricultural uses. According to the Colorado Department of Health - Water Quality Control Division, this segment is meeting all applicable state water quality standards (Ref. 4).

3.3.2 Ground Water

Although the public water supply for Denver is principally surface water, some private wells do use ground water. The principal aquifer in the area is the Denver/Arapahoe aquifer, which lies under the Denver Basin. Wells which utilize the artesian aquifer range in depth from 375 to 600 feet (Ref. 1). There are no public drinking water wells within a five-mile radius of the Arapahoe Station and no ground water is monitored on site.

3.4 Ecological Conditions

Wildlife in the immediate area of the plant consists of deer and small animals (rabbits, rodents). Segment 14 of the South Platte River is considered a warm-water fishery with minnows and suckers constituting the most abundant species. The most significant recreational species in this segment include carp, green sunfish, largemouth bass, white crappie, rainbow trout, brown trout, black bowhead, and channel catfish (Refs. 5, 6, and 7).

According to the Colorado Department of Natural Resources, Department of Wildlife, there are no threatened or endangered species in the immediate area of the Arapahoe Station. However, some of the species which are on the State Species of Special Concern List use the South Platte River downstream of the plant. The only Species of Special Concern which might inhabit the area of the site is the White Pelican (Ref. 8).

3.5 Socioeconomic Resources

The Arapahoe Station is located within the metropolitan area of Denver in Denver County. The 1980 population of Denver was 1,618,461. Growth since 1980 has been the result of natural increase as opposed to in-migration. The median after-tax household buying income in Denver in 1988 was $27,471. In 1988, the unemployment rate was 5.8 percent. Substantial growth has occurred in service industries, aerospace, and high technology electronics, while oil and gas activities continue to be depressed. Companies employing more than 7,500 include U.S. West, Martin Marietta, AT&T, and Continental Airlines (Ref. 9).

3.6 Aesthetic/Cultural Resources

3.6.1 Archaeological/Historical Resources

At Radian's request, the Colorado Historical Society, Office of Archaeology and Historic Preservation, conducted a search of the Colorado Inventory of Cultural Resources for the area surrounding the Arapahoe Station. The search provided information on specific sites from surveys performed in the area. A brief assessment of the status of each site was included in the survey. Included below are the sites which are listed or are eligible for listing on the National Register of Historic Places, and the sites which are within a National Register district. Listed on the Register is Loretto Heights College, 3001 South Federal Boulevard, approximately one and one-quarter miles southwest of the Arapahoe Station. Approximately three-quarters of a mile west of the plant is a site within a National Register district at 2753 - 2755 Umatilla Street. There is also a mill factory at 1314 West Evans Avenue which is officially eligible for listing under the site name of Card Corporation. The Boulevard School located at 2351 Federal Boulevard is also eligible for listing (Ref. 10).

3.6.2 Native American Resources

According to the U.S. Department of the Interior, Bureau of Indian Affairs, there are no existing, federally-recognized Native American tribes in the area of the Arapahoe plant (Ref. 11). The only existing Indian reservations in Colorado are the Ute Mountain Reservation and the Southern Ute Reservation. Both are located in the southwestern corner of Colorado, approximately 225 miles from Denver (Ref. 12).

3.6.3 Scenic or Visual Resources

According to the State of Colorado Highway Department, the closest scenic highway in the area of the Arapahoe plant is the Peak-to-Peak Highway which runs from Estes Park to Central City east of Denver. The South Platte

River which is adjacent to the plant is not listed on the national Wild and Scenic Rivers System (Ref. 13).

3.6.4 Recreational Resources

Several golf courses and city parks are within a two-mile radius of the facility and the Cherry Creek Recreation Area is approximately eight miles southeast of the plant. The nearest state park is Barr Lake, which is approximately 25 miles northeast of the Arapahoe Station. The Pike National Forest is approximately 15 miles south of the plant and the nearest national park is the Rocky Mountain National Park, approximately 50 miles northwest of the facility (Ref. 14).

3.7 Energy and Materials Resources

3.7.1 On-Site Resource Uses

3.7.1.1 Coal

The Arapahoe Station burns primarily low-sulfur bituminous coal mined in Colorado. In 1989, coal consumption by Unit 4 was 289,000 tons. The primary coals utilized by the PSCC at Arapahoe Station are Cyprus Yampa Valley and Empire Energy. Average coal composition data are presented in Table 3-3. Coal storage at the Arapahoe Station varies from 150,000 to 200,000 tons.

3.7.1.2 Water

PSCC has several contracts with the City of Denver to divert up to 5 cubic feet per second (4,000 acre-feet annually) of water from the South Platte River. In 1989, the approximate water withdrawal volume was 1,800 acre-feet. The plant also annually buys approximately 145 acre-feet from the City for potable water and general plant operations.

TABLE 3-3. COAL COMPOSITION

Parameter	Cyprus Yampa Valley As Burned	Cyprus Yampa Valley Dry Basis[a]	Empire Energy As Burned	Empire Energy Dry Basis[a]
Moisture (%)	10.6	--	13.2	--
Ash (%)	9.6	10.7	8.0	9.2
Fixed Carbon (%)	45.4	50.7	45.0	51.9
Volatiles (%)	34.1	38.1	33.8	38.9
Sulfur (%)	0.4	0.4	0.4	0.4
Btu Content (Btu/lb)	13,903	15,500	10,600	12,200
Carbon (%)	62.8	70.2	61.5	70.8
Hydrogen (%)	4.5	5.0	4.5	5.1
Nitrogen (%)	1.6	1.8	1.3	1.5
Oxygen (%)	10.5	11.7	11.1	13.0

Source: PSCC, Fuels Division.

[a]Calculated from "as received" analysis.

3.7.1.3 Power

Since this industrial facility is a power plant, internal power needs are supplied by on-site power generation.

3.7.2 Potential Off-Site Competitors for Resources

According to the Greater Denver Chamber of Commerce, a variety of new industries and manufacturers are locating in the city; however, there are no known plans for any major energy or chemical complexes (Ref. 9).

4.0 CONSEQUENCES OF THE PROJECT

This section presents a comprehensive analysis of anticipated environmental, health, safety, and socioeconomic impacts of the demonstration project.

4.1 Atmospheric Impacts

4.1.1 Construction Phase

The potential for air emission impacts during the construction stage should be very limited. There will be no on-site fabrication, such as tank or silo construction. All project components will be manufactured off site. On-site activity will simply consist of assembling these components (welding, pipefitting). The plant's internal roads, as well as existing foundations from the previous EPRI test facility, are constructed of asphalt or concrete so there is little chance of additional fugitive emissions from construction traffic. However, if required, mitigation measures, such as wetting the work and traffic surfaces, will be implemented.

Additional truck traffic to the site during construction should be minimal; vehicles will transport the urea and reagent injection system components, fly ash handling system, and general construction materials (sheet metal, piping). Any corresponding increase in CO, NO_x, or hydrocarbon emissions should be short-term and insignificant compared to current emissions from the Arapahoe Station and mobile sources in the area.

4.1.2 Operation Phase

4.1.2.1 Conventional Power Plant Emissions

The predominant air quality impact associated with the project will be a reduction in SO_2 and NO_x emissions from the Arapahoe Unit 4 boiler, resulting from a combination of retrofit control technologies. The actual reduction in these emissions will vary throughout the program, however, as each control technology will be studied individually and in combination with the other technologies. Other potential air quality impacts relative to conventional power plant pollutants include particulate matter, carbon monoxide, and carbon dioxide (CO_2). The NAAQS pollutants affected during implementation of the demonstration project include SO_2, CO, and NO_2; the project should not change particulate matter emissions or result in the emission of lead. Depending upon the urea system vendor selected, a 6,000-gallon methanol storage tank may be located on site. However, any volatile organic compound emissions (potential precursors to ozone formation) will be insignificant enough to exempt the unit from permitting.

The program is divided into seven test periods, several of which are further subdivided into major test blocks. The test periods include:

- Baseline Testing--with no associated emissions reductions, to determine emissions at the current condition of the boiler.

- Urea Injection--to determine the effectiveness of urea injection for NO_x control with the existing burner configuration.

- Low-NO_x Burner--to determine the effectiveness of a low-NO_x burner retrofit, with and without the use of combustion air staging ports, in reducing boiler NO_x emissions.

- Low-NO_x Burner/Urea--to evaluate the combined effectiveness of two NO_x control strategies.

- Sodium Injection--the first phase of the test program to achieve a reduction in SO_2 emissions. All testing is to be conducted during low-NO_x burner operation; the last period of this phase will include urea injection for further NO_x control as well.

- Calcium Injection--including both economizer injection and duct injection of lime for SO_2 control. All testing is to be conducted during low-NO_x burner operation, and some portions of this phase will include urea injection for further NO_x control.

- High-Sulfur Coal--a limited period of testing (up to 30 days) to evaluate the effectiveness of low-NO_x burners, combustion air staging ports, urea injection and the more effective of economizer calcium injection or duct calcium injection, at controlling NO_x and SO_2 emissions from a high-sulfur coal-fired plant.

SO_2 emission estimates were made for the sodium injection, calcium injection, and high-sulfur coal test periods. Baseline SO_2 emissions levels were taken from the PSCC proposal (Ref. 15), which listed the level as 880 lb/hr (350 ppmv, dry basis). This level was verified by Radian through a combustion calculation, using the low-sulfur coal analysis also presented in the proposal, and by comparison with SO_2 concentration data summarized in a report published by EPRI (Ref. 16).

The SO_2 emission estimates for the demonstration project test periods are summarized in Table 4-1. The percent reduction levels for each period were estimated from the variation of test conditions proposed during the period, and from available performance data from other sources (Refs. 17 through 21). For the sodium injection tests, there were comparable data available from testing with a similar low-sulfur coal and a fabric filter particulate collector (Ref. 17), but for the calcium injection technologies there was little or no data available for such a combination. Consequently, calcium injection performance was estimated from data for high-sulfur coal and/or for electrostatic precipitators.

Estimates for the high-sulfur coal test period represent a worst case, based on the highest expected coal sulfur content (2.75 percent) and a goal of 50 percent SO_2 removal. If the SO_2 removal technologies to be demonstrated cannot achieve a goal of at least 50 percent removal under the high-sulfur coal conditions, it is likely that this testing would be

TABLE 4-1. SUMMARY OF ESTIMATED SO_2 EMISSIONS

Test Period	Planned Duration (months)	Estimated SO_2 Emission Rate (lb/hr)	Estimated Percent Reduction*
Baseline	2	880	0
Urea NO_x Control	1	880	0
Low-NO_x Burner	3	880	0
Low-NO_x Burner with Urea	2	880	0
Sodium Injection	2	335	62
Sodium Injection with Urea	3	264**	70**
Economizer Calcium Injection	3	484	45
Duct Calcium Injection	3	484	45
High-Sulfur Coal	30 days	2,499***	(284% increase)***

*Based on test conditions listed in PSCC proposal.

**The estimated SO_2 emission rate is lower (and the estimated percent SO_2 reduction is higher) during the sodium injection with urea test period than in the previous test period because of the specific test conditions listed in the PSCC proposal. These estimates are not meant to imply a benefit to SO_2 removal performance by utilizing urea injection.

***Based on a calculated worst-case emission rate of 4,997 lb/hr for Delta No. 6, 2.75 percent sulfur coal; assumes 50 percent SO_2 removal with calcium injection. Despite the emission rate increase during this 30-day period, the net effect of this project will be a reduction of approximately 800 tons of SO_2 emissions during the 12 months of SO_2 removal test periods.

terminated by PSCC in less than the 30-day test period. If PSCC decides to terminate this test period before its planned conclusion, the unit will resume low-sulfur coal firing as soon as the coal bunkers are emptied of the high-sulfur coal (approximately one day or less).

During both the sodium injection and the calcium injection periods, SO_2 emission levels will be significantly reduced (i.e., 45 to 70 percent reduction from baseline). Only during the high-sulfur coal test period (30-day) are the levels estimated to increase (from baseline emissions of 880 lbs/hr to as much as 2,499 lbs/hr, or, stated alternatively, up to 2.37 lbs/million BTU) even though an SO_2 removal efficiency of 50 percent or greater should be achieved during this period. This is because the SO_2 removal during this test period is not estimated to be sufficient to compensate for the increase in coal sulfur level above that of the typically burned low-sulfur coal. However, even though there will be a short-term emission increase, the overall net effect of the project during the SO_2 removal periods will be an estimated 800 tpy decrease in SO_2 emissions from Unit 4.

Impacts of the test program on ambient air quality with respect to SO_2 concentrations were also considered by Radian. During the first five test periods (baseline testing, urea injection, low-NO_x burner, low-NO_x burner/urea, and sodium injection), no adverse effects to ambient air quality are expected to result because stack-gas SO_2 concentrations are either unaffected by the testing or are reduced, and stack temperatures are not significantly affected by these tests. Therefore, stack-gas SO_2 concentrations are not increased, and stack-gas dispersion characteristics are not altered. Maximum ground-level SO_2 concentrations should either decrease or be unaffected during these test periods.

Radian also evaluated the potential impact of flue gas humidification and the resultant cooling of stack-gas temperatures during the duct calcium injection test periods on stack plume buoyancy and SO_2 dispersion. A USEPA screening model, SCREEN-1.1, was used to model these effects. A conservative assumption that humidification to a 20°F approach to adiabatic saturation (the lowest value in the test plan) was used in the modeling exercise. During operation with duct calcium injection and humidification to a 20°F approach to adiabatic saturation, SO_2 removal levels of 50 to 70 percent should be achieved. The case of 50 percent removal and humidification to a 20°F approach to adiabatic saturation was compared to baseline operation with a 250°F stack gas temperature and an SO_2 emission rate of 880 lb/hr. The model result does reflect an increase in the maximum one-hour ground-level SO_2 concentration, from 122 $\mu g/m^3$ at 1,400 meters from the stack (baseline), to 123 $\mu g/m^3$ at a similar distance. For reference purposes, the 3-hour SO_2 significance level concentration under the Prevention of Significant Deterioration (PSD) program is 25 $\mu g/m^3$; the PSD de minimus levels are often used in assessing the significance of site-specific changes in NAAQS concentrations. In this instance, the projected SO_2 increase of 1 $\mu g/m^3$ during the flue gas humidification and duct calcium injection test portion of the demonstration project is well below the 3-hour de minimus level of 25 $\mu g/m^3$. Therefore, for this period, as well as the first five test periods, no significant effect on ground-level ambient air SO_2 concentrations is expected. During the seventh test period (high-sulfur coal), a measurable increase in the ground-level ambient air SO_2 concentrations is expected. However, this test period will be limited to up to 30 days.

NO_x emissions were estimated for each of the seven test periods. These estimates, which are summarized in Table 4-2, indicate that the most significant reduction (70 percent compared to baseline) will occur during the test period in which the low-NO_x burners and the urea injection system are used. Baseline emissions were taken from the PSCC proposal, which listed NO_x emissions at 1,663 lb/hr (as NO_2), or 920 ppmv (dry basis). This estimate was compared with data in an earlier EPRI document (Ref. 22) which reports that baseline NO_x levels for Arapahoe Unit 4 averaged 1,030 ppmv (dry basis at 3 percent O_2). After correcting this earlier value to a more representative stack flue gas oxygen level of approximately 5 percent, the EPRI value is consistent with the PSCC estimate. The earlier data were collected during a pilot-scale investigation of selective catalytic reduction for NO_x control conducted by EPRI at the Arapahoe test facility which drew a slipstream of flue gas from Arapahoe Unit 4.

TABLE 4-2. SUMMARY OF ESTIMATED NO_x EMISSIONS

Test Period	Planned Duration (months)	Estimated NO_x Emission Rate (lb/hr as NO_2)	Estimated Percent Reduction*
Baseline	2	1,663	0
Urea NO_x Control	1	1,214	27
Low-NO_x Burner	3	898	46
Low-NO_x Burner with Urea	2	499	70
Sodium Injection**	2	832	50
Sodium Injection with Urea**	3	499	70
Economizer Calcium Injection**	3	665	60
Duct Calcium Injection**	3	665	60
High-Sulfur Coal**	30 days	665***	60***

*Based on test conditions listed in PSCC proposal.

**These test periods include low-NO_x burner operations as well. Some portions of the economizer calcium injection, duct calcium injection, and high-sulfur coal test periods will also include urea injection for further NO_x control.

***Assumes NO_x levels are approximately the same as for the low-sulfur coal portions of the demonstration.

The effects of the XCL low-NO_x burner retrofit were estimated from previously published data for the retrofit of these burners to a wall-fired unit (Ref. 23). Although the NO_x production characteristics of the top-firing configuration of the Arapahoe Unit 4 boiler are different from that of a more conventional wall-fired unit, these are the best comparison data available. To make this estimate more conservative (i.e., to produce higher emission estimates), the lower, "un-tuned" NO_x reduction measured for this wall-fired retrofit was used as the basis for the Unit 4 percent reduction estimate. The effects of the combustion air staging ports were also estimated from data in Reference 23.

It is possible that the NO_x reductions resulting from the XCL burner retrofit to the Unit 4 top-fired boiler will be greater than what was measured for the conventional wall-fired unit. The multi-tip "burners" currently in service on Unit 4 are simply pipes that empty the coal/primary air mixture into the furnace cavity, in close proximity to where the secondary or combustion air is introduced. Under this arrangement, there is little that can be done to tune the burners for lower NO_x emissions, thus the relatively high current NO_x emissions levels (920 ppmv, dry at 3 percent oxygen). Given this baseline, it is entirely possible that the XCL burners will be more effective on a percent reduction basis than in the previous retrofit of a more conventional wall-fired unit.

Also, the XCL burner typically produces a relatively long flame, so that flame impingement on the water wall across the furnace from the burner becomes a concern in retrofits. In the previously cited wall-fired XCL burner retrofit, the ability to adjust the burner for maximum NO_x emissions reductions was constrained by the need to compress the flame to avoid impingement. With the top-firing configuration of the Unit 4 boiler, the flame will travel along the longest dimension of the furnace. The impingement constraint on burner adjustment should not be encountered, and the XCL burner retrofit may be more effective than in a typical wall-fired case.

The effectiveness of urea injection in reducing NO_x emissions were somewhat difficult to predict, because only limited previous data are available. Also, the vendor of the urea injection system has not yet been selected, and the two candidate vendors (Nalco/Fuel Tech and BTU Services, Inc.) take different approaches to applying the technology. However, more published data were available for the Nalco/Fuel Tech system (Refs. 24 and 25) than for the BTU Services system (Ref. 26), for coal-fired utility applications. Consequently, the estimates for the effectiveness of urea injection were based on data previously published by Fuel Tech (prior to acquisition by Nalco).

The NO_x emission estimates show a significant reduction for all phases of the project except the initial baseline tests. The target NO_x emission reduction (70 percent) should be achieved during the testing with urea injection, in combination with the low-NO_x XCL burner and the combustion air staging ports.

Although overall NO_x emissions will be reduced during all but the baseline period, the NO_2 content of the remaining NO_x will likely be increased as a result of the injection of sodium reagents into the flue gas for SO_2 control (Refs. 17, 27, 31). The mechanisms for this byproduct reaction are not well understood, but it appears that flue gas NO is oxidized to NO_2 while sodium sulfite (Na_2SO_3) is oxidized to sodium sulfate (Na_2SO_4). Also, if methanol is added to the boiler as part of the urea injection scheme, some NO to NO_2 conversion may occur there as well (Refs. 29 and 30). At sodium injection conditions which result in 70 percent removal with the low-sulfur coal fired in Arapahoe Unit 4, approximately 50 to 60 ppmv (dry basis) of NO_2 would be expected to be converted from flue gas NO across the FFDC (Ref. 17). While this level of NO_2 does not represent an atmospheric emission problem in itself, it may lead to the production of a slight brownish plume exiting the stack.

There are two factors which will diminish the effects of plume coloration during this project. One is that Unit 4 shares a stack with Unit 3, diluting the concentration of NO_2 in the combined gases. The other effect is that at normal sodium injection temperatures (i.e., about 250°F to 350°F), ammonia in the flue gas will react with NO_2, converting it to ammonium nitrate solids that are collected in the FFDC and/or reducing it back to colorless NO.

A number of calculations have been conducted in an effort to estimate these effects. The worst case for plume coloration would be for the flue gas NO_2 level to be at its highest expected value (about 50 to 60 ppmv, dry basis), with Unit 3 off line. For these conditions, and taking into account the 14-foot diameter of the Unit 3/Unit 4 stack, the plume coloration has been estimated to produce about 5 percent opacity, which may be readily visible under certain atmospheric conditions. A more normal circumstance would be for both units to be on line, in which case the NO_2 concentration in the combined gases would be reduced to about 35 to 45 ppmv (dry basis). For this condition, the plume coloration has been estimated to produce an opacity level in the range of 3 to 4 percent. While this level should be less obvious than the higher level estimated with Unit 3 off line, it could still be visible under certain atmospheric conditions. However, the opacity range would be well below the 20 percent maximum allowable opacity level in Regulation No. 1, II.A.1 of the Colorado air pollution regulations.

As stated in Section 2.1.2.2, the urea injection process has an optimum temperature range of 1,700°F to 1,900°F. At lower temperatures, side reactions can occur which produce ammonia. It is possible that small amounts of ammonia could be emitted from the Unit 4 stack during the urea injection project phase. The ammonia slip estimated to occur because of the injection of urea for NO_x control, however, will have a beneficial effect on plume coloration. For the case where ammonia slip is controlled below 10 ppmv, reaction of ammonia with flue gas NO_2 would be expected to reduce NO_2 levels by at most 2 to 3 ppmv. However, if the urea system is operated under conditions where the ammonia slip is equimolar relative to the amount of NO_2 being produced with the sodium injection, a more significant reduction in NO_2 levels would be estimated to occur (Ref. 27). At these conditions, the combined Unit 3 and Unit 4 stack gas NO_2 concentrations are estimated to be reduced to the range of 25 to 35 ppmv (dry basis), and the observed opacity is estimated to be in the range of 2 to 3 percent. This level is the threshold at which plume coloration can be detected by most persons, and, therefore, would likely be a relatively obscure effect only visible under certain atmospheric conditions. Because of these reactions within the sodium injection system, ammonia slip levels are estimated to remain below 20 ppmv (Ref. 27).

Thus, by optimizing the integration of urea injection for NO_x control and sodium injection for SO_2 control, the effects of plume coloration should be reduced to minor levels. At the same time, ammonia slip levels should be reduced to less than half of what might be predicted from furnace exit ammonia concentration levels.

Particulate emissions are not expected to be affected by the test program, in spite of the fact that sodium- and calcium-based solid reagents will be injected into the flue gas during some test periods. A reverse-gas FFDC is used as the particulate control device on Arapahoe Unit 4, and particulate emissions from well-performing reverse-gas FFDCs tend to be relatively insensitive to inlet particulate loading. In one full-scale demonstration of sodium injection for SO_2 control in a similar low-sulfur coal application, however, outlet emissions from a reverse-gas FFDC were observed to double after sodium injection was initiated (Ref. 17). However, it appeared that the increase was a result of a number of leaking filter bags. A trend had been observed for several years prior to that demonstration for greater emissions from the fabric filter module as the bags aged. Particulate emissions due to bag leaks would tend to increase in proportion to the inlet mass loading. Thus, bag leaks provide the best explanation for why the FFDC outlet emissions levels doubled during that sodium injection demonstration. A later sodium injection demonstration at this same facility, conducted after a number of defective fabric filter bags had been replaced, saw no measurable increase in particulate emissions when sodium injection was implemented (Ref. 27). Because PSCC has an effective bag maintenance program for the Arapahoe Unit 4 FFDC, no effect on particulate emissions should be observed during the sodium injection tests. No effect on FFDC particulate emissions would also be expected during the calcium injection tests at Arapahoe Station either, for the same reasons.

The NO_x control measures are not expected to have an impact on particulate emission rates, since particulates are controlled at Unit 4 by a FFDC and not an electrostatic precipitator. There is a possibility that the carbon content of the fly ash produced will be increased after the low-NO_x burners are placed in service. An XCL burner retrofit to a wall-fired boiler caused the carbon content of the ash to nearly triple after burner tuning efforts were completed, from 2.2 percent to about 6 percent (Ref. 23). However, even this level of increase would only increase the particulate loading to the FFDC by about 4 percent. This level of increase would not have a measurable impact on FFDC performance. Increased carbon carryover can be a concern for electrostatic precipitator particulate control devices. Higher carbon carryover rates can adversely affect electrostatic precipitator particulate control performance, as the carbon has a low electrical resistivity and is not efficiently collected. This phenomenon is not a concern, however, with a FFDC, such as Unit 4's.

Carbon monoxide (CO) emission rates could be increased by the program, although this effect is not certain. Data from intermittent measurements conducted by PSCC indicate that at normal furnace O_2 levels of 4 to 5 percent, flue gas CO concentrations typically measure 40 to 50 ppmv (dry basis at 3 percent O_2) (Ref. 28). For the flue gas flow rate (1.236×10^6 lb/hr) and unit capacity factor (60 percent) listed in the PSCC proposal, baseline Unit 4 CO emission levels are estimated at approximately 96 to 120 tpy. PSCC will limit any increase in CO levels in the flue gas to an additional 40 ppmv above the base level, to keep the resulting increase below 100 tpy, the level which would trigger regulatory new source review in this ozone nonattainment area.

It is likely that operation of the new XCL low-NO_x burners at conditions resulting in optimum NO_x emission reductions could increase flue gas CO emission levels above the current level of approximately 40 to 50 ppmv (dry at 3 percent O_2). In a previous full-scale demonstration of the retrofit of XCL burners on a wall-fired utility boiler, CO emissions at excess air levels corresponding to the lowest NO_x emission rates were observed to increase from 20 ppmv (old burners) to 115 ppmv with the as-installed XCL burners (Ref 23).

Even after tuning of the XCL burners, CO emissions at optimum NO_x reduction conditions remained at 60 ppmv. Because of the nonattainment status of the Denver area with respect to ambient CO levels, the primary criterion for setting boiler operating conditions once the XCL burners are installed will be to maintain CO emission levels at or below a level that is approximately 40 ppmv (dry at 3 percent O_2) higher than current levels. This will limit the increase in CO emissions to below 100 tpy.

Because it is the amount of increase above the current level of CO emissions that is pertinent for purposes of determining whether new source regulatory review is triggered by this demonstration project, it is important that the baseline CO emission levels be well established. Currently, PSCC can only estimate the current CO emission levels from the results of a limited number of grab-sample measurements of CO concentrations. Once the continuous emissions monitoring equipment is placed in service during the baseline portion of the demonstration period, it will provide the opportunity to measure CO emissions under current Unit 4 operating conditions on a continuous basis. The average CO emission level for the baseline test period should, therefore, provide the basis from which any increase in CO emissions is quantified.

The injection of urea for further NO_x emission reductions can produce byproduct CO in the flue gas (Ref. 25). The production of CO resulting from urea injection is minimized by injecting in higher furnace temperature regimes, which may not be ideal for optimum NO_x emission reductions. Consequently, during this demonstration the ability to reduce flue gas NO_x emission levels by urea injection may be limited to less than optimum levels by the need to avoid significant increases in flue gas CO levels.

Furthermore, it is possible that methanol or other oxygenated hydrocarbon additives used to enhance urea effectiveness and control ammonia slip during urea injection could cause an additional increase in CO emissions (Refs. 29 and 30). The production of CO by ammonia slip additives is minimized by limiting the amount of additive relative to the NO and SO_3 content of the flue gas at the point of injection, and by controlling the flue gas time-temperature relationship at and beyond the point of additive injection. It is desirable from a cost standpoint to minimize the use of ammonia slip additives. Most of the urea injection testing will be conducted without these additives; they will be used only on an as-needed basis. Furthermore, if additives are used at all, dosage rates and injection conditions will be constrained by the need to avoid any resulting increase in CO emissions.

Carbon dioxide (CO_2) levels in the flue gas will be increased slightly during the urea injection and sodium injection periods of the test program. During urea injection, each mole of urea [$(NH_2)_2CO$] injected should produce one mole of CO_2 in the flue gas. Similarly, each mole of sodium bicarbonate ($NaHCO_3$) reagent injected during the sodium injection test periods will release 1 mole of CO_2 upon thermal decomposition, and each mole of sodium sesquicarbonate ($NaHCO_3 \cdot Na_2CO_3 \cdot 2H_2O$) or trona reagent will release 2 moles of CO_2. However, even at the highest anticipated injection rates for the combination of urea and sodium reagents, no more than approximately 1,000 ppmv (dry basis) of CO_2 would be added to the flue gas. This represents a maximum of about three-quarters of a percent of the total amount of CO_2 in the flue gas, an insignificant increase. In fact, an increase in the CO_2 content of the flue gas of this magnitude is within the normal variation resulting from swings in as-delivered coal ultimate analysis and BTU content.

4.1.2.2 Other Atmospheric Emissions

There are other potential impacts of the demonstration program that are not typical of conventional power plant operation. These are associated with the potential presence of ammonia (NH_3) in the flue gas from utilization of the urea injection system. In addition to being an undesirable atmospheric pollutant, ammonia can combine with flue gas moisture and any sulfur trioxide (SO_3) to produce ammonium sulfate or bisulfate. These byproduct solids can cause boiler air heater pluggage and corrosion. Furthermore, ammonia can potentially react with hydrocarbons in the furnace gas to produce dialkyl amines. Finally, there is the potential for insignificant emissions of volatile organic compounds from the methanol tank if BTU Services is selected as the urea system vendor.

Ammonia emissions or "slip" is a byproduct of urea injection for NO_x control. When urea is injected in the furnace in the proper temperature regime, two moles of NH_2 free radical are produced which will selectively and non-catalytically reduce flue gas NO to nitrogen (N_2). However, this reaction is not 100 percent efficient, and a portion of the excess NH_2 ends up leaving the furnace as ammonia in the flue gas. The amount of ammonia emitted can be controlled by limiting the urea-to-NO_2 mole ratio, by varying the urea injection location(s), and by the injection of methanol or other oxygenated hydrocarbons. The conditions that are optimum for avoiding ammonia emissions, or "slip", may not be consistent with conditions that are optimum for NO_x control. However, it appears that significant NO_x emission level reductions (i.e., 40 percent reductions relative to the NO_x levels after the low-NO_x burner retrofit) can be achieved while maintaining ammonia emissions or "slip" below 10 ppmv in the flue gas (Ref. 24 through 26). This ammonia slip value corresponds to an emission rate of approximately 7 lb/hr. Furthermore, even some of this ammonia would likely be removed from the gas phase before being emitted. A portion of the ammonia would likely be adsorbed on the fly ash being collected in the FFDC and, as discussed previously, a portion would likely react with NO_2 formed during sodium injection for SO_2 control. It may be desirable to maintain ammonia slip from the furnace at levels higher than 10 ppmv during the sodium injection portions of the demonstration to provide more ammonia to react with higher NO_2 levels. Although some of this increased ammonia slip would be consumed in reactions with NO_2 formed downstream of the air heater, it is possible that ammonia slip values at the stack may increase to approximately 20 ppmv (14 lbs/hr) during these periods (see discussion starting on pg. 4-10).

A USEPA screening model, SCREEN-1.1, was used to estimate maximum ground-level ammonia concentrations that would result from ammonia slip at 14 lbs/hr. The worst case was with Unit 3 (which shares the stack with Unit 4) off line, and during humidification of the Unit 4 flue gas to a 20°F approach to adiabatic saturation. The maximum one-hour ground-level ammonia concentration was estimated at 5 $\mu g/m^3$. This concentration appears to be well below levels where any adverse effects of ammonia on terrestrial plants would be expected (Ref. 31).

Another Air Emission issue during the demonstration project involves the possible formation of dialkyl amines, which are precursors to carcinogens in the form of nitrosamines. It is possible that these carcinogen precursors will be formed in the furnace during urea injection, through reactions of the urea decomposition products with unburned hydrocarbons in the flue gas. However, as demonstrated in the following paragraphs, concentrations of dialkyl amines, if any, should be insignificant.

This issue has been raised in relevant literature for selective catalytic reduction (SCR) systems applied to fossil-fuel fired units for NO_x emission control. In the SCR process, ammonia is injected into flue gas at about 350°C to catalytically reduce flue gas NO by reactions similar to the non-catalytic reactions that will occur during the urea injection phases of this demonstration. A preliminary screening study report prepared by Alanova, Inc., for a proposed SCR-equipped gas-fired turbine cogeneration plant, estimated a worst-case scenario where the production of an example dialkyl amine carcinogen precursor, diethylamine, could result in an increased cancer risk in the most affected area near the plant of 200 per one million persons (Ref. 32). (It should be noted that for purposes of the study, the researchers used conservatively high values of dosage and potency estimates to intentionally overestimate risks.) There may be a question, therefore, as to whether, similar to the reactions potentially occurring in SCR-equipped systems, the ammonia and/or NH_2 radical which is formed upon decomposition of urea injected into the boiler can react with any hydrocarbons remaining in the furnace gas to produce dialkyl amines, such as diethylamine.

To estimate the potential for such reactions during this demonstration project, Radian performed equilibrium calculations for the reaction between ammonia and ethane (an example unreacted hydrocarbon species), to form a specific dialkyl amine, diethylamine (the same species evaluated in the SCR study mentioned above). The calculations were performed using a proprietary Radian computer program that uses the technique of free energy minimization to determine chemical equilibrium. The reaction evaluated by these calculations was:

$$2\ C_2H_6 + NH_3 \rightarrow NH(C_2H_5)_2 + 2H_2$$

However, the calculations also allowed a competing reaction to occur: decomposition of the ammonia to form nitrogen and hydrogen. The calculations were based upon a 900°C furnace temperature, atmospheric pressure, 500 ppm of C_2H_6, and 1000 ppm ammonia. The ammonia concentration is within the range of possible ammonia or NH_2 radical formation from the thermal decomposition of injected urea (prior to any reactions with furnace gas NO or further decomposition). The hydrocarbon concentration was purely an estimated worst case, as no data for a top-fired coal unit are available. The calculations assume that equilibrium is achieved, with possible reaction products being hydrogen, nitrogen, and diethylamine. The equilibrium value calculated for diethylamine formation would only be realized if the kinetics of the reactions discussed above were much more rapid than the rate of cooling of the flue gas below 900°C, as lower temperatures are less favorable for the formation of diethylamine.

The results of the equilibrium calculations indicate that the estimated equilibrium diethylamine concentration in the Unit 4 flue gas (corresponding to the stated assumptions) may be approximately 6×10^{-11} ppm. The flue gas diethylamine concentration estimated in the Alanova screening study mentioned above was about 100 million times higher. That study, which predicted a worst-case increased cancer risk of 200 per million persons, was based on a diethylamine concentration that was 10^8 times (100 million times) greater than the concentration estimated for this demonstration. By comparison, then, the potential cancer risk implications of this demonstration should be negligible.

Volatile Organic Emissions may be emitted in small amounts if BTU Services is selected as the urea system vendor. The BTU Services system would include a 6,000-gallon methanol storage tank for the control of ammonia slip. However, emission estimates for the proposed tank indicate that emissions would be below 1 tpy (see Section 5.1 for emission estimate basis). Therefore, these emissions should not be a concern for this ozone nonattainment AQCR.

4.1.2.3 Coal and Materials Handling

Low levels of particulate emissions could potentially be generated during the operational phase of the integrated dry NO_x/SO_2 emission control system project. Potential sources of these emissions include the temporary storage of the high-sulfur test coal, the calcium and sodium reagent receiving, storage, and processing facilities, and the fly ash storage silo. Although, as explained in Section 5.1, these emissions will not be high enough to trigger state permitting or development of a fugitive particulate control plan, PSCC will implement ash, reagent, or coal emission suppression measures as needed.

The high-sulfur coal will be transported to the Arapahoe Station by rail cars. The material will be stored in a pile in the plant yard of approximately 1.5 acres in size. As needed during the 30-day test period, the coal will be transferred by conveyor to the existing bunkers for Unit 4. Approximately 30,000 tons of high-sulfur coal will be used during the test period. Fugitive emissions for the high-sulfur coal pile were calculated based on emission factors from the USEPA document Compilation of Air Pollutant Emission Factors (AP-42) for storage piles (Ref. 33). Emissions from wind erosion are calculated to be 540.7 pounds during the 30-day test period. Emissions from coal loading are calculated to be 18.3 pounds. Total emissions from storage of the high-sulfur coal, therefore, is estimated to be 559 pounds.

The calcium and sodium injection systems will be designed to minimize emissions. Reagent will be received via enclosed pneumatic trucks and loaded into one of the two 150-ton enclosed storage silos. Reagent will then be fed from the storage silos by pneumatic conveying systems to the pulverizers. Each pneumatic conveying system will consist of a rotary feeder, sorbent feed pump, transfer blower, and air dryer. Pulverizers will be used to grind the reagent to a mean particle size of approximately 18 microns. This is approximately the same size as the fly ash particles. The pulverizer will be an impact mill which accelerates the solid matter on a rotating disc containing eight tungsten carbide hammers. The accelerated material will impact against a ceramic liner which reduces the particle size. Two fans will be located at the outlets of fabric filters which will collect the ground reagent. The ground reagent will collect in the hopper portion of the fabric filters prior to injection into the flue gas duct. The reagent will then be fed into the furnace or duct through an enclosed pneumatic injection system.

Emissions from the dry reagent injection system were calculated based on AP-42 factors for crushed limestone storage piles because emission factors for the pneumatic transfer system and the silo storage system are not available. These factors are based on emissions resulting from the loading of aggregate onto open storage piles. A 75 percent reduction of emissions was applied by Radian to account for the controls provided by the enclosed storage and transfer systems planned for the demonstration project. Emissions from sodium storage for the project were estimated at 38 lbs/yr and emissions from calcium storage were estimated at 44 lbs/yr (Ref. 33).

An enclosed silo will also be constructed to store the dry ash from Unit 4's FFDC. The solids leaving the FFDC will pass through feeders and will be entrained by the enclosed pneumatic transport system to the ash silo. The silo will be fitted with dust collection equipment, and, as needed, the ash may be wetted to facilitate handling and to minimize emissions. The emissions for the fly ash storage silo were also calculated based on AP-42 factors for crushed limestone storage piles with a 75 percent reduction applied by Radian to account for the emission control provided by the enclosed silo and pneumatic transfer system. Estimated emissions for the fly ash system are 309 lbs/yr.

In summary, the increase in particulate emissions as a result of coal and material handling during the project is estimated to be 951 lbs/yr (0.48 tpy).

4.1.2.4 Noise

The additional trucks and equipment needed for the demonstration project will contribute to the noise level in the plant. However, these sources are expected to be insignificant, in relation to the noise levels from current plant operations. Since the surrounding land use is industrial in nature, there are no sensitive receptors that should be affected by the project noise levels.

4.1.3 Post-Demonstration Phase

The goal of this project is to demonstrate an integrated, retrofit control strategy that will ultimately reduce current SO_2 and NO_x emissions by approximately 70 percent each. If the demonstration proves to be acceptable, without adverse impacts on the commercial operation of the Unit 4 boiler, these emission reduction levels may be retained during the post-demonstration period. Thus, SO_2 emissions should be reduced from the current level of 880 lb/hr to a level of 264 lb/hr, and NO_x emissions should be reduced from the current level of 1,663 lb/hr (as NO_2) to a level of 499 lb/hr. The worst case, which is quite unlikely, is that all of the technologies being demonstrated prove to be ineffective and/or unacceptable for commercial operation of the unit. In this case, SO_2 and NO_x levels would return to their current, baseline levels.

Other atmospheric impacts during the post-demonstration period could include changes in CO, CO_2, or ammonia emissions, or plume coloration. The magnitude of these impacts will be dependent on the results of the demonstration program, and on which of the technologies remain in operation.

4.2 Land Impacts

The area required for new construction for this demonstration will be minimal. The urea injection system will require an area of approximately 25 ft by 70 ft. The dry reagent injection system (for sodium and calcium reagents) will mostly be contained within an existing building that is approximately 25 ft by 33 ft. A new building approximately 15 ft square, and two reagent storage silos occupying an area of about 15 by 33 ft, will also be built. The dry fly ash waste storage and unloading silo to be built to handle the dry sorbent injection system and fly ash wastes will occupy an area about

30 ft square. These areas total less than 0.1 acre, including the existing building. Even tripling this area to allow for walkways, truck access, and pipe supports, the total land use impact at the site from the demonstration units is virtually negligible at less than one-third of an acre. Approximately 30,000 tons of high-sulfur coal will be stored on site in a segregated area for the limited test period; the area affected by this storage should be approximately 1.5 acres.

New construction for the demonstration units will occupy land area where there are numerous existing foundations (remaining from the previous EPRI research facility adjacent to Unit 4) and that is completely paved. The coal storage area is adjacent to the existing low-sulfur coal storage area. Therefore, no existing undisturbed land area in the vicinity of Arapahoe Unit 4 will be affected by this project.

4.3 Solid Waste Impacts

4.3.1 Ash Impacts

As discussed below, the primary impacts on Unit 4's existing fly ash characteristics will be due to the sodium injection and calcium injection periods of the project. It is possible that the low-NO_x burner and combustion air staging ports phases of the test program will slightly increase the combustible carbon content of the fly ash. An XCL burner retrofit to a wall-fired boiler caused the carbon content of the ash to nearly triple after burner tuning efforts were completed, from 2.2 percent to about 6 percent (Ref. 23). However, even this higher figure is within the range of existing combustible carbon content of the Arapahoe Unit 4 ash (Ref. 28), so ash characteristics would not be markedly altered. It is possible that a small amount of ammonia slip during urea injection would adsorb on the fly ash. However, even at an ammonia slip rate of 20 ppmv (dry basis), if this entire amount was adsorbed on the fly ash it would only amount to about 12 ppb (weight basis) in the solids.

The NO_x control measures would not be expected to have an impact on bottom ash characteristics. These solids remain at furnace temperatures for some time before being withdrawn from the bottom of the boiler, so no combustibles or urea decomposition products should be present.

During the sodium injection and calcium injection portions of the test program, the quantity of ash produced by Unit 4 will be increased by the addition of very soluble sodium salts and slightly soluble calcium compounds. During sodium injection, it has been estimated that the quantity of combined bottom ash, fly ash, and sodium wastes produced would average about 23 percent greater than the current rate for bottom ash and fly ash alone, from about 9,700 lb/hr to about 11,900 lb/hr. During calcium injection tests, the combined bottom ash, fly ash, and calcium waste production rate would increase by an average of about 27 percent over the current bottom ash and fly ash rate, to about 12,400 lb/hr. Using the above estimates, along with estimates for the solid waste production during the high-sulfur coal test period, the total solid waste disposal quantity (bottom ash, fly ash) for the planned one-year SO_2 removal portion of the demonstration has been estimated at approximately 34,000 tons, a 32 percent increase over the current Unit 4 ash quantity of approximately 26,000 tpy.

The Unit 4 fly ash stream will be stored on site in a silo, and then trucked off site for disposal. [The current management practices for Unit 4 bottom ash (on-site storage prior to off-site disposal) will not change.] The fly ash waste is not expected to have any water quality impact at the Arapahoe Unit 4 site, since it will be kept completely separate from any ground- or sluice-water contact. The ultimate disposal site for these wastes will be a PSCC or third-party operated landfill. The landfill will be sited, designed, constructed, permitted, and operated in accordance with Colorado solid waste facility management rules. Consequently, the soluble and slightly soluble species present in these wastes are not expected to affect groundwater quality at the ultimate disposal site.

4.3.2 Other Industrial Solid Waste

Asbestos insulating material will be removed from and around Unit 4 prior to installation of the low-NO_x burners. PSCC has established contractual commitments with a number of authorized asbestos disposal landfills in Colorado. PSCC or its removal contractor will ensure that the material is properly packaged, labelled, and transported off site for disposal.

4.3.3 Hazardous Waste

The demonstration project will not result in the generation of hazardous waste as that term is defined in the federal Resource Conservation and Recovery Act (RCRA), as amended, the Colorado Hazardous Waste Management Act, and implementing rules.

4.4 Water-Quality Impacts

The demonstration is not expected to adversely affect the quality of wastewater that is continuously discharged from the power plant via Outfall 001 to the South Platte River. During approximately one year of this demonstration period, sodium or calcium reagents will be injected into the Unit 4 flue gas to remove SO_2. To avoid altering the characteristics of wastewater discharged to the South Platte River with soluble sodium salts, or slightly soluble calcium salts, the Unit 4 fly ash will be segregated from the existing ash management system. A receiver vessel will be installed in the line between the Unit 4 FFDC hoppers and the jet eductor through which the sluice water flows. This receiver, which will be equipped with its own small fabric filter, will prevent any of the fly ash and sodium or calcium solids pulled from the Unit 4 FFDC hoppers from entering the ash sluice system. The water flowing through the jet eductor and being pumped to the ash sluice ponds will remain free of solids.

Because the jet eductor will still be used, the total volume of water flowing through the sluice system will not be changed. Furthermore, no sodium or calcium salts will come into contact with the water. The quality of the water being returned to the river may actually be improved. Any soluble species which dissolve from the bottom ash from all of the units and fly ash from the other units should be diluted by the relatively clean water being returned from the jet eductor for the Unit 4 fly ash. This relatively clean water from the Unit 4 fly ash jet eductor will lower the overall solids content of the slurry being pumped to the primary settling pond. Because solids generally settle faster from more dilute slurries, it is possible that the suspended solids level in the water being returned to the South Platte River will be reduced by this demonstration.

Another potential impact on water quality would be surface runoff from the demonstration area itself, where the reagent and urea systems and ash storage silo will be located. As discussed in Section 4.10 (Health and Safety Issues), plant personnel will receive proper emergency response training for the new materials to be used in the demonstration project, and careful materials handling and expansion of the existing MCP/SPCC plan to address potential spills from these systems should ensure that runoff remains relatively free of constituents associated with the materials in storage in this area. Furthermore, the vacuum pneumatic transport system that will be used to transport the unit fly ash is inherently spill-free in operation, as air tends to leak in, rather than solids leak out. Also, this vacuum system is available to clean up spills in the vicinity of the FFDC by connecting a flexible hose to one of the vacuum pipes. Finally, in the event of a major spill which is not otherwise contained and does reach the ash ponds, the discharge point to the river can be blocked to prevent off-site impacts.

With respect to coal-pile runoff, all runoff from the low-sulfur coal piles currently drains to a low spot on the plant site for evaporation. During the short-term storage of the high-sulfur coal, runoff, if any, will similarly drain to this evaporation area.

Although there is no available information on existing ground-water quality at the site, the demonstration project should not affect the condition of this water. There are no new land disposal units and existing ash pond water characteristics should not be adversely impacted by the project.

4.5 Ecological Impacts

The integrated dry NO_x/SO_2 emission control project will not adversely affect terrestrial or aquatic plant or animal life at or near the Arapahoe Station. The project will take place at an existing industrial site and, since it will mainly entail physical, above-grade changes in the boiler and new construction on an already paved area, will not necessitate any land disturbance activities.

As described in Section 2.1.2.4, although river-water requirements should temporarily increase as a result of the demonstration project (estimated to increase by 45 acre-feet or 0.040 mgd over 1989 levels during the highest water usage year of the project), the increase should not adversely affect water flow in, and ecology of, the South Platte River. The increase is well within year-to-year variations in the plant's river-water use. The plant's overall river-water consumption during this one-year SO_2 removal period (1,800 acre-feet per year plus the 45 acre-feet per year increase) will be less than the maximum river-water consumption in previous years of operation of the Arapahoe Station. Therefore, aquatic plant or animal life should not be affected by implementation of the project.

4.6 Socioeconomic Impacts

The project should have little effect on the local economy. Construction and operations workers will consist of contractors' and PSCC personnel; implementation of the project should not necessitate any new hiring. Many of the raw materials being utilized in the project will be purchased outside of the Denver area.

4.7 Aesthetic/Cultural Resource Impacts

There should be no effect on aesthetic/cultural resources as a result of implementation of the integrated NO_x/SO_2 emission control project. First, the project will take place at an existing industrial site where there are no aesthetic or cultural resources to be impacted. There are no scenic areas or national or state parks and forests in the immediate vicinity of the project. The city recreational areas (parks and golf courses) within 2 miles of the plant should not be affected by the demonstration project. In any event, since the modifications do not involve land disturbance or significant construction activities, there will be no potential effect on cultural properties either listed in or eligible for listing in the National Register of Historic Places and there are no known Native American tribal affinities to the site.

4.8 Traffic Impacts

The demonstration will impact vehicle traffic in the area of the Arapahoe Station to a small degree. There will be a number of additional shipments to the power plant to deliver sodium and calcium reagent, urea, and any additives. Also, trucks will be used to haul away the dry fly ash stream to an off-site disposal facility. However, because the Unit 4 fly ash will no longer be sluiced to the on-site ash settling ponds, the truck volume required to haul away the remaining ash sludge from the station will be correspondingly reduced.

Several calculations were made to quantify these impacts. First, the reduction in truck traffic required to haul away the wet ash from the sluice pits was estimated. This ash is dried to approximately 40 percent moisture, and PSCC reports that each truck can haul 40 tons. Ash production was estimated at design (100 MW) firing conditions, and a 60 percent capacity factor (typical operating time in a year, taking into account planned and unplanned down times) was considered in the calculations. For continuous full-load operation, the numbers discussed below should be increased by approximately two-thirds.

It is estimated that an average of two trucks per day are required to haul away the fly ash from Unit 4, taking into consideration a 60 percent capacity factor for the unit. The number of trucks required to haul away the dry fly ash and sodium or calcium wastes was similarly estimated. Material balance calculations were conducted to estimate the truck traffic, assuming that the dry wastes are wetted to 15 percent moisture to control dusting, and the same 40-ton weight limit per truck. For both the sodium and calcium injection/low-sulfur coal test periods, the truck hauling rate estimate remained at approximately two trucks per day, even though the sodium or calcium injection increases Unit 4 fly ash volume. The truck count did not increase significantly above the current ash sludge hauling truck rates because the higher moisture content of the current wastes all but offsets the additional fly ash mass resulting from sodium or calcium injection. During the thirty days planned for high-sulfur coal testing, however, the waste hauling rate was estimated to double to 4 trucks per day.

The rates for shipping reagents to the site were also estimated from material balance calculations. Again, a 60 percent unit capacity factor was considered. In most cases, the reagents will be shipped in from nearby states, so an interstate weight limit of 25 tons per truck was assumed. For the sodium reagent, rates were calculated for sodium sequicarbonate, because greater mass rates will be required to achieve 70 percent SO_2 removal than with sodium bicarbonate. On the average, about one truck per day will be required to deliver sodium reagents. For lime reagent, because of the lower molecular weight, less than one truck per day will be required during the low-sulfur coal test period (actually about two trucks every three days). During the planned 30-day high-sulfur coal test period, the lime delivery rate should average between three and four trucks per day.

Urea and additive injection rates are less straightforward to estimate than the sodium or calcium reagents, because the baseline NO_x levels after the low-NO_x burners are installed are not yet known. However, assuming that the low-NO_x burners and overfire air achieve a 50 percent reduction, that urea is added at an average normalized stoichiometric ratio of 1.0, and that it will be delivered as a 40 weight percent solution, less than one truck every two days will be required on the average to maintain the inventory on site. It is difficult to quantify the delivery rate for ammonia slip additives given the uncertainty in the need for their use, but qualitatively it would seem that cost constraints would limit these deliveries to even less frequency than for the urea.

In summary, the solids waste hauling truck rate will not be measurably affected by the demonstration period, except during the planned 30-day high-sulfur coal test. Then, an additional two trucks per day will be required. During urea injection tests, one truck will be required to deliver the urea solution every other day. Other additives will be delivered even less frequently. During the SO_2 removal phases of the demonstration, sodium or calcium reagent deliveries will amount to one truck per day or less during the low-sulfur coal portion, and between three and four trucks per day during the 30-day high-sulfur coal period. Relative to the normal daily traffic rate along South Platte River Drive in the vicinity of the power plant, this increase represents a negligible effect. The South Platte River Road is designed for industrial traffic and has recently undergone minor improvements in the area of the Arapahoe Station. Recent traffic volume studies are not available; however, the increased volume will be slight as the project site is located away from the main traffic congestion area of the city.

4.9 Energy and Material Resource Impacts

Table 4-3 summarizes the changes in current plant energy and material resource utilization from the demonstration project.

Impacts from the proposed demonstration on the area infrastructure will be negligible. Energy requirements will increase only slightly, if at all, during most test periods of the project. Only during periods of duct calcium injection testing, where humidification of the flue gas will occur, will appreciable increases in station electrical energy requirements occur. The compressors required to supply compressed air to the nozzle during this period will consume up to 730 kw of electricity. This represents almost a ten percent increase in the Arapahoe Station house power. However, this increase may be partially offset by a 100 kw or greater reduction in induced draft fan power for Unit 4, due to the decreased flue gas volumetric flow rate that results from the gas shrinkage upon cooling, and corresponding decreases in flue gas pressure drop across the FFDC.

TABLE 4-3. PROJECT RESOURCE REQUIREMENTS

Resource	Plant Requirements w/o Project (1989 Basis)	Additional Requirements w/Project
Coal (Unit 4)	289,000 tpy	no change (high-sulfur coal offsets low-sulfur coal consumption)
River Water	1,800 acre-feet/yr	up to 45 acre-feet/yr (estimated increase for 1994)
Potable Water	145 acre-feet/yr	9 acre-feet/yr
Land	Approx. 80 acres	<1/3 acre for demonstration units (within existing 80 acres)
sulfur		<1.5 acres for high-coal storage (within existing 80 acres)
Sodium	None	5,000 to 7,000 tpy
Calcium	None	5,000 to 8,000 tpy
Urea	None	484,000-2,420,000 gpy
Methanol	None	169,000 gpy
Chemical Additives	None	Not Specified

Coal requirements will remain unchanged; the coal required for the limited high-sulfur coal test will displace consumption of the low-sulfur coal normally fired. Water needs will be increased slightly during utilization of the urea and humidification systems. Approximately 45 additional acre-feet per year (0.040 mgd) of river water will be needed during an approximately 12-month period (estimated to occur in 1994) for certain test phases and can easily be obtained from the South Platte River within the existing contractual agreement with the City of Denver. The sodium reagents to be tested in the dry reagent injection system will be obtained from the following vendors: trona from Tenneco Materials, sesquicarbonate from FMC, and sodium bicarbonate from Church & Dwight, all located in the Green River area of Wyoming. If nahcolite (naturally occurring sodium bicarbonate) is tested, it will come from the western slope of Colorado. Although there are no nahcolite mines open at the present time, there are plans from two vendors to open mines in the 1991 time frame. The calcium reagent, calcium hydroxide, will be purchased from one of several vendors most likely in Arizona or Utah. Urea is readily available commercially and may be purchased from Coastal Chemical Co. in Cheyenne, Wyoming. Methanol and the chemical additives are also readily available and will be supplied by BTU Services or Nalco/Fuel Tech, respectively.

4.10 Health and Safety Issues

4.10.1 Construction

Construction activities for the demonstration project will include installation of the urea and sorbent injection systems, control room, ash storage silo, and humidification system, and replacement of the existing burners with the low-NO_x burners. Asbestos-containing insulating material will be removed from the boiler roof and duct work as a part of the burner replacement activity.

With respect to general construction activity, the construction standards of the federal Occupational Health and Safety Administration (OSHA) at 29 CFR Part 1910 and the State of Colorado construction standards will be applicable to the project. Compliance with these standards will be the responsibility of the particular contractor.

With respect to asbestos removal, PSCC will likely utilize one of several authorized contractors in the state to conduct the removal and disposal program. PSCC will ensure that the contractor implements the required regulatory notices, work practices, packaging, labelling, and disposal practices. PSCC's procedures for asbestos abatement, which incorporate federal NESHAPs and OSHA rules and state rules, are contained in the PSCC manual entitled Asbestos Standards and Procedures Electric Operations August 11, 1989.

4.10.2 Operations

Operation of the demonstration should present no unusual or atypical health and safety hazards. The project will utilize three new chemicals not currently in use at the plant.

Urea--a urea solution in tank storage will be utilized during several of the NO_x control phases of the project. Urea is an organic, natural gas-based chemical. The primary feedstocks for urea production are ammonia and carbon dioxide. Urea is formed by reacting ammonia and carbon dioxide to form ammonium carbamate. The carbamate is then dehydrated to form urea and water. Based on manufacturer information, the solution is nonflammable, nonreactive, and noncarcinogenic. There is no known occupational exposure limit for the chemical. Its visual appearance is a hazy light amber liquid. Personal protective equipment, such as gloves and goggles, are recommended in typical use of the solution.

Methanol--one urea system vendor proposed for the project, BTU Services, would utilize methanol on an as-needed basis to control ammonia slip from the system. The methanol would be stored in a 6,000-gallon above-ground tank adjacent to the urea system. Methanol is a colorless, flammable liquid. Storage requirements for this flammable liquid are found in the federal OSHA rules at 29 CFR Part 1910, Part H, Section 1910.106. This rule requires: 1) adherence to nationally recognized design standards for the construction of steel and nonsteel flammable liquid storage tanks; 2) venting practices and compliance with vent design standards; 3) spill containment by natural or manmade grading to a secure location, or diking of a size sufficient to retain the entire capacity of the tank; and 4) adequate structural and foundation support. The threshold limit value (TLV) for methanol is 200 ppm. Gloves, protective goggles, and clothing to prevent prolonged skin contact are required when working with methanol. Respirators are not required below 2000 ppm.

Chemical Additives--the other potential urea system vendor described in PSCC's proposal, Nalco/Fuel Tech, would utilize chemical additives on an as-needed basis to control ammonia slip from the system. The unspecified additives would be stored in a 10,000-gallon above-ground tank. Based on manufacturer information, the additives are nonflammable, nonreactive, and noncarcinogenic. The chemicals do, however, contain 10 weight percentage of an oxygenated hydrocarbon. Personal protective equipment, such as gloves and goggles, are recommended in typical use of the product.

None of the chemicals described above are on the list of extremely hazardous substances, defined at 40 CFR Part 355, which are regulated under the federal and state Emergency Planning and Community Right-to-Know Act.

The plant's existing OSHA hazard communication program will be expanded to address the routine and nonroutine hazards associated with the new chemicals to be used in the demonstration project. The training will include a review of the pertinent Material Safety Data Sheets, use of personal protective equipment, and proper emergency response procedures for contingencies such as spills or fires. The existing plant MCP/SPCC program will be revised to address containment (diking or protective grading) features of the demonstration unit area, and spill response procedures. Additional training, in addition to adherence to nationally recognized design and construction standards for the tank and silo systems, should substantially minimize health and safety risks of the project.

4.11 Impact Summary

This section summarizes the anticipated environmental, health, safety, and socioeconomic impacts of the integrated dry NO_x/SO_2 emission control system project.

The positive effects of implementing the integrated dry NO_x/SO_2 emission control system project at Unit 4 include an estimated 70 percent decrease in SO_2 emissions during the highest SO_2 reduction period (sodium injection with urea injection) and an estimated 70 percent decrease in NO_x emissions during the highest NO_x reduction period (low-NO_x burners with urea injection). The nitrogen dioxide content of the remaining NO_x emissions will increase during the sodium injection phase. That is, during this phase, more of the NO_x will be emitted as NO_2 rather than NO, but overall NO_x emissions will not increase. Potential plume coloration impacts associated with a higher NO_2 content are expected to be below state opacity limits. Particulate matter emissions should not change. CO emission increases will not exceed 100 tpy as a result of implementation of low-NO_x controls. Low rates of ammonia may be emitted from the Unit 4 stack as a result of utilization of the urea injection system.

There should be no demonstrable impact on the local economy as there will be no new hiring during the construction and operation phases. Existing PSCC and contractor employees will be used.

The demonstration project units will affect an area of less than one-third acre on existing Arapahoe Station land adjacent to Unit 4. This land is within the former site of an EPRI test facility and already features a concrete surface. The storage of high-sulfur test coal for the limited test period will encompass an area of approximately 1.5 acres adjacent to the existing coal storage site.

Except for asbestos to be removed from the boiler during the construction stage, the only impact of the demonstration project on solid wastes will be a modification in Unit 4 fly ash characteristics and an increase in volume. Approximately 34,000 tons per year of Unit 4 ash (bottom and fly) will be produced, representing a 32 percent increase over baseline. The fly ash stream produced during the sodium injection phase will contain soluble sodium species of concern for landfill disposal. The fly ash will be stored on site prior to off-site disposal in a secure landfill. Unit 4 bottom ash will continue to be sluiced to the on-site ash ponds for temporary storage prior to off-site disposal.

The volume and characteristics of wastewater should not be affected by the project.

The plant's existing OSHA compliance policies and procedures should be adequate for the project. During construction, any contractors will comply with all site rules and regulations concerning health and safety procedures. Depending upon the urea system vendor selected, methanol may be stored on site to control potential ammonia slip. Because methanol is a flammable liquid, the storage tank will be designed to meet OSHA requirements and the appropriate project personnel will receive training in proper contingency response procedures.

4.11.1 Mitigation Measures

Mitigation is defined at Section 1508.20 of the Council on Environmental Quality's rules to include "avoiding, minimizing, rectifying, reducing, or eliminating, or compensating for impacts." This subsection describes mitigation measures for the impacts identified in Section 4.

4.11.1.1 Air Quality

PSCC will primarily implement the demonstration project with a low-sulfur (0.4 percent sulfur) coal. However, the project is also designed to measure system performance during a 30-day period with a high-sulfur coal (2.51 - 2.75 percent sulfur) that would be more representative of midwestern and eastern U.S. utility operations. Because the expected levels of SO_2 removal during the demonstration period cannot offset the higher sulfur content of the Illinois coal, SO_2 emissions are estimated to increase during the test period from a baseline of 880 lbs/hr to 2,499 lbs/hr. However, in spite of this emission increase during the high-sulfur coal test period, the overall net effect of the SO_2 removal portion of the demonstration will be an estimated 800 tpy decrease in SO_2 emissions from Unit 4. To mitigate ambient air quality impacts during the high-sulfur coal test period, PSCC plans to conduct the test during a very limited period (30 days), which will still allow meaningful performance data to be secured. If the desired SO_2 emission reduction is not being achieved during this time period, PSCC may elect to terminate the test before the conclusion of the 30-day period.

CO levels may also increase from implementation of the low-NO_x controls. Since the AQCR is nonattainment for CO, an increase would be a concern from an ambient air quality and regulatory perspective. To avoid triggering a significant net emission increase of CO (100 tpy), PSCC will reduce the efficiencies of the low-NO_x controls planned for the project.

Ammonia slip may occur from utilization of the urea injection system for NO_x control. Ammonia emissions are estimated to amount to 14 lbs/hr or less. Potential urea system vendors propose to use either methanol or proprietary chemical additives to control the formation of ammonia slip to less than half this level. However, greater ammonia slip levels will have a beneficial impact in reducing tendencies for brown-plume formation during the sodium injection period, as mentioned below.

An increase in the NO_2 content of the remaining NO_x emissions may produce a slight brown discoloration to the stack plume during sodium reagent injection. Additional urea, or ammonia, could be injected into the flue gas downstream of the air heater to reduce NO_2 levels produced during sodium reagent injection. However, this would have the adverse effect of further increasing ammonia slip from the unit.

4.11.1.2 Surface-Water Quality

To mitigate the potential impact of Unit 4 demonstration project fly ash on existing wastewater quality and management procedures, PSCC will segregate the fly ash from the on-site ash sluice and disposal system for off-site disposal.

Surface water run off from the plant site drains via a series of yard sumps and underground drains to the ash pond system. It is possible that run off from the demonstration unit area (less than one-third acre in size) could exhibit characteristics of the chemicals to be used in the process (urea, calcium and sodium reagents, chemical additives). PSCC will mitigate this possibility by, first, ensuring that chemical transfer will be performed in a manner that will minimize spill potential (i.e., using enclosed or covered conveyors). Secondly, the existing site MCP/SPCC plan will be amended to address spill prevention, containment, and response procedures in the demonstration area. Spills can be isolated in the ponds; therefore, a release to the river is unlikely.

4.11.1.3 Ground-Water Quality

There will be no new on-site solid waste or wastewater disposal units associated with the project. Unit 4 fly ash will be segregated from the current on-site ash management system for off-site disposal. Since there will not be changes in the existing on-site ash and wastewater management system, no specific ground-water quality mitigation measures are planned.

Unit 4 fly ash will be disposed of off site in a third-party or PSCC landfill. To minimize potential ash impacts on groundwater, the disposal unit will be designed, constructed, permitted, and operated in compliance with applicable state and federal regulations.

4.11.1.4 Health and Safety

Depending upon the urea system vendor selected, methanol may be stored at the site in a 6,000-gallon above-ground storage tank. Methanol is a flammable liquid, and, thus, its storage poses a potential health and safety risk. However, the hazard potential will be minimized by designing the tank in accordance with the OSHA requirements for flammable liquid storage at 29 CFR Part 1910.106. These rules require adequate and compatible materials of construction, tank and vent design pursuant to a nationally-recognized standard, protective venting practices, and spill containment features through either grading or diking. Safety and hazard communication training for the chemicals to be used in the project will be provided to appropriate personnel.

4.11.2 Monitoring

The test phase of the demonstration project includes a number of monitoring activities that are designed to evaluate process efficiency and environmental parameters of the project. The test protocol for the anticipated monitoring has been submitted to the DOE in a draft Environmental Monitoring Plan (EMP). Once approved, the EMP will establish an information base for assessing the environmental performance of the NO_x/SO_2 emission reduction technologies and will document the extent of compliance monitoring activities. These activities are NEPA-independent; i.e., they are driven by the requirements of the CCT-III program itself, as well as conventional regulatory compliance requirements. However, the activities will yield data relating to potential impact-forcing source terms of the project. This section overviews the monitoring that is anticipated for the test phases of the program that is relevant to EHSS source terms.

Process evaluation monitoring for all systems of the project will include continuous gas analysis, batch or wet chemical sample analysis, particulate ash sampling, coal and pulverizer sampling/analysis, and temperature measurements. Continuous gas analyzers will be used to monitor NO/NO_x, NO_2, O_2, CO_2, CO, SO_2, N_2O, and NH_3 in the flue gas. Particulate matter will be quantified and characterized by measuring the unburned carbon content of the ash, measuring the quantity of particulate emissions at the inlet and outlet of the fabric filter, and measuring the particulate size distribution.

The waste and effluent testing program will measure and characterize the solid waste, the solid waste leachate, and simulation of leachate impacts in a landfill environment. Testing will assess the chemical, physical, and mineralogical properties of the waste including:

Total element content	Bulk mineralogy
Density	Load-bearing strength
Water content	Heat of hydration
Particle size distribution	Compressibility

Analysis of the leachate will include the following:

pH	Iron
Carbonate	Manganese
Conductivity	Selenite/Selenate
Total Dissolved Solids	Arsenite/Arsenate
Calcium	Cadmium
Sodium	Magnesium
Sulfide/sulfate/sulfite	Chromium
Chloride	Zinc
Nitrate/nitrite	Lead
Fluoride	Copper
Molybdenum	Barium
	Silicon

Leachate testing may also include evaluation of the potential presence of polycyclic aromatic hydrocarbons.

5.0 REGULATORY COMPLIANCE

This section describes the regulatory programs currently applicable to the Arapahoe Station and the anticipated regulatory implications of the demonstration project.

5.1 Air Quality

Air emissions from the Arapahoe Station are subject to the federal Clean Air Act and the Colorado Air Quality Control Act; the state and federal programs are administered by the Air Pollution Control Division (APCD) of the Colorado Department of Health. The plant is in AQCR 3 of Colorado, which is in attainment for all NAAQS pollutants except for carbon monoxide, particulate emissions, and ozone.

The four generating units at the Arapahoe Station do not currently have air permits because each unit was constructed prior to February 1, 1972, the date of initiation of the permitting program of the APCD. However, the units are subject to the state opacity standard and SO_2 limits. Pursuant to Regulation 1, II.A.1., each source is prohibited from emitting any air pollutant which is in excess of 20 percent opacity. Pursuant to Regulation 1, VI.A.3.a.(ii), SO_2 emissions are limited to 1.2 lbs/million BTU. PSCC files a quarterly report with the APCD which provides compliance information for the opacity and SO_2 standards. The Arapahoe Station does not have continuous emission monitoring systems for SO_2; therefore, SO_2 emissions are calculated from the amount of sulfur in the fuel. Opacity is monitored by continuous opacity monitoring systems.

As discussed in Section 4.1, the anticipated changes in air emissions from Unit 4 due to the demonstration project are summarized as follows:

> <u>SO_2 emissions</u> will be reduced from a baseline level of 880 lbs/hr to 264 lbs/hr during the highest SO_2 reduction period (sodium injection with urea). However, during the 30-day high-sulfur coal test period,

emissions will be increased from baseline to 2,499 lbs/hr, or approximately 2.37 lbs/million BTU.

NO_x emissions will be reduced from a baseline of 1,663 lbs/hr to 499 lbs/hr during the highest NO_x reduction period (low-NO_x burners with urea).

NO_2 emissions from sodium injection could result in a brown coloration to the stack plume. As a worst-case estimate (NO_2 at its highest levels of 50-60 ppmv, dry basis, and Unit 3 off-line), the coloration could result in an opacity level of approximately 5 percent.

Particulate matter emissions are not expected to change.

CO level increases will not exceed 100 tpy.

Ammonia and, possibly, volatile organic compounds (VOCs), will be emitted in low amounts.

Coal and material handling fugitive emissions may increase by approximately 0.48 tpy.

Therefore, the emission increases associated with the project are for SO_2 (limited high-sulfur coal test only), NO_2, CO, NH_3, VOCs, and fugitive particulates from coal and material handling. With respect to the brown coloration potentially associated with NO_2 emissions during sodium injection, the 5 percent opacity estimate is well below the APCD Regulation 1 allowable maximum of 20 percent, and the Unit 4 stack does not currently exceed the opacity limit. The estimated increase in emissions associated with the high-sulfur coal storage, sodium/calcium system, and ash silo (0.48 tpy) is small enough to exempt these sources from state permitting requirements pursuant to Regulation 3., III.D.1.e. (less than 1 tpy exempt). PSCC is also exempted from the requirement to develop a fugitive particulate emission control plan pursuant to Regulation 1., III.D.1.b. If needed, however, fugitive particulate emission control measures, such as wetting work or traffic surfaces, will be implemented.

Vendor estimates indicate that ammonia emissions can be controlled to approximately 3.5 lbs/hr, or 9 tpy, through the use of chemical additives. However, during sodium injection for SO_2 control, it may be desirable to allow ammonia slip values to increase to approximately 14 lbs/hr or 36 tpy to reduce stack NO_2 concentrations. PSCC will pursue the regulatory implications of the estimates, but it is possible that the State could exempt de minimis emission rates from State permitting requirements. It is not readily possible to compare these estimates to current ammonia emissions in AQCR 3. The State does not monitor ammonia and the data for ammonium in particulates is not available.

VOCs may be emitted in small amounts if BTU Services is selected as the urea system vendor. The system would include a 6,000-gallon methanol storage tank for the control of ammonia slip. Using AP-42 factors for organic liquid storage tanks (which take into account breathing and working losses from a fixed-roof tank), Radian has estimated that VOC emissions from this potential source would be approximately 0.84 tpy. Regulation 3., III.D.1.e. and 5. of the State rules exempt from permitting sources emitting less than 1 tpy of VOCs in ozone nonattainment areas. Therefore, the source, if constructed, should not be of regulatory or environmental concern in this ozone nonattainment area.

Since AQCR 3 is attainment for SO_2, the Prevention of Significant Deterioration (PSD) permitting program applies if there is a net increase in SO_2 emissions from the project of 40 tpy. Although there will be an increase in emissions during the planned 30-day high-sulfur coal test period, the increased emissions will be more than offset by the reductions achieved during the one-year SO_2 removal demonstration period. In fact, the SO_2 emissions during the one-year period are estimated to be reduced by approximately 800 tpy in spite of the SO_2 increase during the high-sulfur coal test period. Because of the potential for an exceedance of the State SO_2 standard (1.2 lbs/million BTU) during the 30-day high-sulfur coal test, PSCC will pursue, as needed, a State variance.

Since the AQCR is nonattainment for CO, new source review and the requirement to achieve lowest achievable emission rates will apply if there is a significant net emission increase of CO. The significance level for CO is 100 tpy, pursuant to Colorado Regulations 3,IV.D.2. and Common Provisions, G. Definitions. In the optimization of the NO_x control technologies, any result-

Definitions. In the optimization of the NO_x control technologies, any resulting increase in flue gas CO levels will be limited by PSCC to less than 40 ppmv (100 tpy) above current levels.

Unit 4 is currently not subject to the federal and state New Source Performance Standards (NSPS) for electric utility steam-generating units at 40 CFR Part 60, Subpart Da, and Regulation 6, IIA., respectively. These NSPS apply to any modification of an existing facility, as well as to new facilities. The term "modification" is defined to mean "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any contaminant to which a standard applies". However, pursuant to the NSPS rules, a modification does not necessarily include "the addition or use of any system or device whose primary function is the reduction of air pollutants." PSCC will, therefore, seek a determination from the USEPA headquarters in Washington, D.C., and the Colorado APCD that the innovative emission reduction technologies to be demonstrated at the Arapahoe Station will not constitute a modification for NSPS purposes.

The issue of an NSPS or PSD modification may also arise at the conclusion of the project if and when Unit 4 is returned to its predemonstration physical and operating condition. The USEPA has issued a "research-related no-action" assurance to at least one midwestern utility innovative emission reduction project on the basis of a November 16, 1984 headquarters policy memorandum. That memorandum states than an agency assurance not to enforce a legal requirement against a regulated party can be provided where "... clearly necessary to serve the public interest...or to obtain important information for research purposes and which no other mechanism can address adequately." The USEPA cited these reasons for issuing the "research-related no-action" assurance to the midwestern utility. Similarly, PSCC has received "research-related no-action" assurance statements from the regional office of the USEPA and the Colorado APCD.

There is no National Emission Standard for Hazardous Air Pollutants (NESHAP) applicable to the operations phase of the project.

5.2 Solid Waste

5.2.1 Ash Impacts

The volume, characteristics, and method of storage and disposal of Unit 4 fly ash will change as a result of the project. As described in Section 4.3.1, the total quantity of Unit 4 ash (bottom ash and fly ash) produced during the sodium injection phase will increase from a baseline of 9,700 lbs/hr to 11,900 lbs/hr, and will increase during the calcium injection period from 9,700 lbs/hr to 12,400 lbs/hr. The current Unit 4 bottom ash and fly ash disposal rate of approximately 26,000 tpy will increase by 8,000 tpy, to a total of approximately 34,000 tpy. The Unit 4 fly ash will be segregated for storage in an on-site silo prior to truck transport off site to an authorized solid waste disposal facility. The volume and characteristics of Unit 4 bottom ash will not be affected by the project and the current disposal method of sluicing to an on-site ash pond prior to off-site disposal will continue to be utilized.

The issue of acceptable off-site disposal options for Unit 4 fly ash is being considered by PSCC in the context of finding a regional site for ash from a number of stations within the PSCC system. Currently, PSCC is evaluating siting and operating its own disposal facility in Weld County, approximately 15 miles northeast of Denver, in an area which is hydrogeologically suited to landfill disposal. Alternatively, PSCC may work with an operating third-party landfill which is currently used by the utility, to upgrade the site for Unit 4 fly ash disposal. However, regardless of the off-site option selected, the facility will comply with the Colorado waste facility siting and operating standards at 6 Colorado Code of Regulations, Article 2. These standards prohibit the siting of disposal facilities in floodplains and in areas where sources of drinking water may be adversely affected. Depending on characterization of the waste material, the design standards include double or single liners constructed of synthetic or natural materials, a leachate collection and removal system, and upgradient and downgradient monitoring wells, completed to an appropriate impervious layer or to bedrock, to allow sampling of the ground water to determine if it has been affected by facility operations.

5.2.2 Other Industrial Solid Waste

Removal of asbestos will be necessary during the low-NO_x burner installation phase. PSCC has an established program for asbestos handling. The program is outlined in the PSCC manual Asbestos Standards and Procedures Electric Operations. The procedures outlined in the manual were established to comply with 40 CFR Part 61, Subpart M (Clean Air Act NESHAP requirements relating to asbestos removal); 29 CFR Part 1910 (OSHA requirements for occupational exposure to asbestos and work practices); and Code of Colorado Regulations, Title 5, Chapter 1001. The asbestos which is removed from Unit 4 will be disposed of in an off-site approved landfill.

5.2.3 Hazardous Waste

Hazardous waste generated at the Arapahoe Station is subject to regulation under RCRA, the Colorado Hazardous Waste Act, and implementing rules. The Arapahoe Station, a small-quantity generator of hazardous waste, is assigned USEPA ID No. COD980285951. The only hazardous wastes (as defined by these two acts) generated at the Arapahoe Station are waste degreasing solvents, waste oils, and used batteries. These wastes are presently reused on site or are stored for less than 90 days before being transported off site for recycling at a USEPA-approved facility. No additional hazardous wastes are expected to be generated during the demonstration project.

5.3 Wastewater

PSCC's discharge of wastewater into the South Platte River at the Arapahoe Station is regulated under the federal Clean Water Act and the Colorado Water Quality Control Act. The Colorado Department of Health, Water Quality Control Division, has been delegated the federal National Pollutant Discharge Elimination System (NPDES) permitting program by the USEPA. The Arapahoe Station has been issued Colorado Wastewater Discharge Permit No. CO-

0001091, which authorizes the following outfalls: (1) Outfall 001--process water from the emergency ash pond and the ash polishing pond, (2) Outfall--002 an emergency bypass of Outfall 001, and (3) Outfall 003-005--three outfalls for non-process river water. Effluent quality requirements are subject to federal Effluent Regulations for Steam Electric Power Generating Point Source Category, State Effluent Standards, and State Water Quality Standards for the receiving stream, which are summarized in Table 5-1.

An amendment to this permit will not be required for the integrated dry NO_x/SO_2 emission control system project. No new effluents will be generated by the project, nor will there be a change in the characteristics or volumes of currently generated wastewaters.

5.4 Water Supply

The Arapahoe Station has several contracts with the City of Denver authorizing the diversion of 1 to 5 cubic feet per second of water from the South Platte River, or up to 4,000 acre-feet per year. The plant also buys water from the City for potable water and process water uses. The additional water needed for the urea and humidification systems can easily be obtained within the existing contracts.

5.5 Health and Safety

The health and safety requirements applicable to operation of the integrated flue gas control demonstration project include the "construction" and "general industry" standards of the federal OSHA at 29 CFR Parts 1910 and 1926, respectively. In addition, Colorado has health and safety regulations applicable to the proposed project. These standards include requirements relating to walking-working surfaces, means of ingress and egress, operation of powered equipment, adequate ventilation, noise exposure controls, fire protection, and electrical equipment safeguards. Arapahoe Station employees are already instructed in worker protection and safety procedures under the existing PSCC Manual of Safe Practices. It is anticipated that current procedures, with some updated training for chemicals to be used in the project,

TABLE 5-1. ARAPAHOE STATION COLORADO WASTEWATER DISCHARGE PERMIT (CO-0001091) LIMITATIONS (SUMMARY)

Outfall/Parameter	Limitation
Polishing Pond (Outfall 001)	
Flow	1.00 MGD
Total Suspended Solids	
30-day average	30 mg/L
Daily maximum	100 mg/L
Oil and Grease	
30-day average	15 mg/L
Daily maximum	20 mg/L
PCBs	No Detectable Amount
Total Residual Chlorine	0.11 mg/L
pH	6.5 - 9.0 S.U.
Temperature	86°F
Total Zinc	0.88 mg/L
Total Chromium (federal provisions)	
30-day Average	0.2 mg/L
Daily Maximum	0.2 mg/L
126 Priority Pollutants Except Zinc and Chromium	No Detectable Amount
Chemical Metal-Cleaning Wastes	No Discharge
Emergency Response (Outfall 002)	Same Effluent Limitations as Outfall 001
River Water (Outfalls 003-005)	
No Process Water Shall be Added to Outfalls 003-005 (river water only)	

will adequately ensure that federal and state standards are met. During construction, the contractors will comply with all site rules and regulations concerning health and safety procedures.

The asbestos abatement will be conducted by either PSCC personnel or contractors in accordance with the PSCC manual entitled Asbestos Standards and Procedures Electric Operations in order to ensure the health and safety of the employees and the public. PSCC's manual incorporates the federal asbestos regulations at 40 CFR Part 61, Subpart M (NESHAPS), 29 CFR Part 1910 (OSHA requirements for acceptable occupational exposure levels and specification of work practices), Colorado Air Pollution Control Regulation 8 (emission standards for asbestos), and Section 8 of the Colorado Waste Facility Siting rules (relating to asbestos disposal).

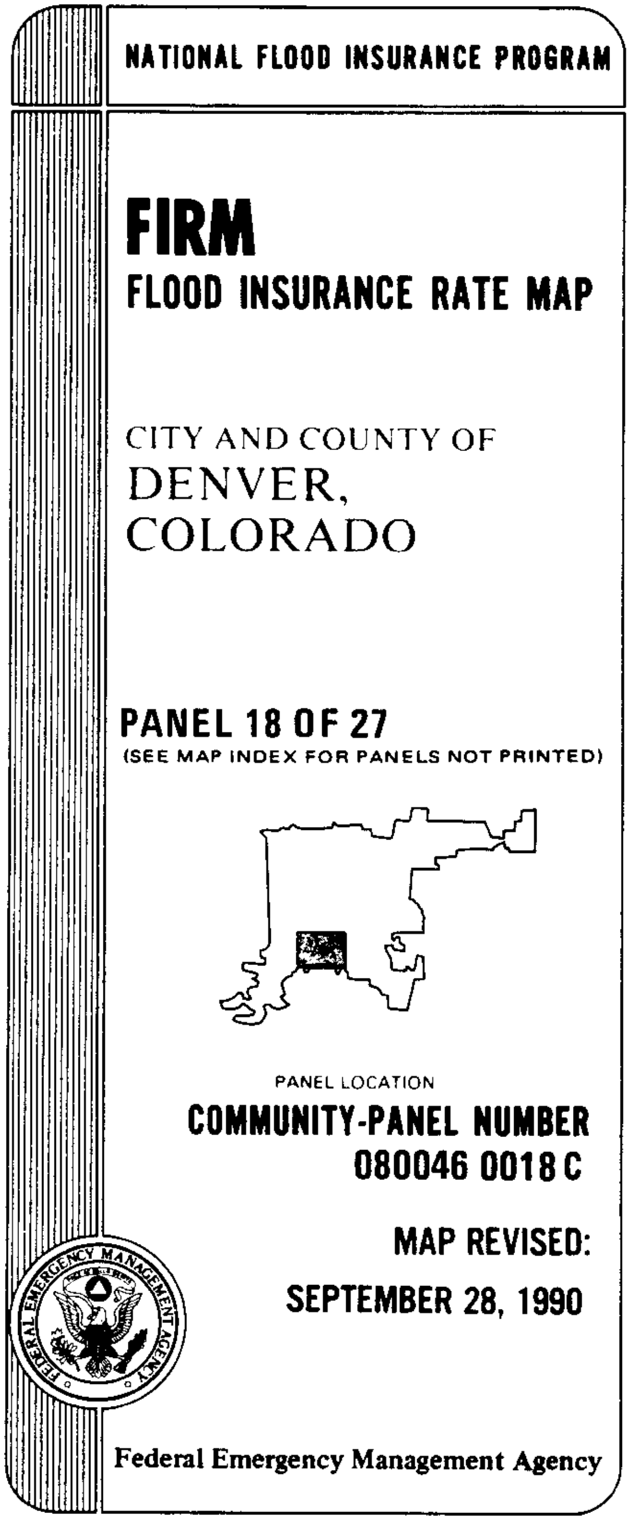
The demonstration project is not expected to require the storage and/or use of any "extremely hazardous substances" as that term is defined under the Superfund Amendments and Reauthorization Act Title III (Emergency Planning and Community Right-To-Know) program. Thus, no EPCRA Title III emergency planning notification appears applicable to the project.

5.6 Floodplain/Wetlands

5.6.1 Floodplain

Executive Order 11988, Floodplain Management (May 24, 1977) requires federal agencies, such as the DOE, to consider the effect of proposed actions, such as the CCT-III program, on floodplains. The intent of the program is to ensure that alteration of a floodplain by implementation of a proposed action not change or affect flood levels or velocities during a flood event, thereby adversely impacting adjacent property.

Figure 5-1 illustrates that a portion of the Arapahoe Station is within Floodplain Zone AO (area of 100-year flood depths of 1 to 3 feet), as identified by the Federal Emergency Management Agency Flood Insurance Rate Map



NATIONAL FLOOD INSURANCE PROGRAM

FIRM

FLOOD INSURANCE RATE MAP

CITY AND COUNTY OF
DENVER,
COLORADO

PANEL 18 OF 27
(SEE MAP INDEX FOR PANELS NOT PRINTED)

PANEL LOCATION

COMMUNITY-PANEL NUMBER
080046 0018 C

MAP REVISED:
SEPTEMBER 28, 1990

Federal Emergency Management Agency

Figure 5-2. Federal Emergency Management Agency, Flood Insurance Rate Map

LEGEND

SPECIAL FLOOD HAZARD AREAS INUNDATED BY 100-YEAR FLOOD

ZONE A	No base flood elevations determined.
ZONE AE	Base flood elevations determined.
ZONE AH	Flood depths of 1 to 3 feet (usually areas of ponding); base flood elevations determined.
ZONE AO	Flood depths of 1 to 3 feet (usually sheet flow on sloping terrain); average depths determined. For areas of alluvial fan flooding, velocities also determined.
ZONE A99	To be protected from 100-year flood by Federal flood protection system under construction; no base elevations determined.
ZONE V	Coastal flood with velocity hazard (wave action); no base flood elevations determined.
ZONE VE	Coastal flood with velocity hazard (wave action); base flood elevations determined.

FLOODWAY AREAS IN ZONE AE

OTHER FLOOD AREAS

ZONE X	Areas of 500-year flood; areas of 100-year flood with average depths of less than 1 foot or with drainage areas less than 1 square mile; and areas protected by levees from 100-year flood.

OTHER AREAS

ZONE X	Areas determined to be outside 500-year flood plain.
ZONE D	Areas in which flood hazards are undetermined.

	Flood Boundary
	Floodway Boundary
	Zone D Boundary
	Boundary Dividing Special Flood Hazard Zones, and Boundary Dividing Areas of Different Coastal Base Flood Elevations Within Special Flood Hazard Zones.
513	Base Flood Elevation Line; Elevation in Feet*
(D)——(D)	Cross Section Line
(EL 987)	Base Flood Elevation in Feet Where Uniform Within Zone*
RM7 X	Elevation Reference Mark

*Referenced to the National Geodetic Vertical Datum of 1929

NOTES

This map is for use in administering the National Flood Insurance Program; it does not necessarily identify all areas subject to flooding, particularly from local drainage sources of small size, or all planimetric features outside Special Flood Hazard Areas.

Areas of special flood hazard (100-year flood) include Zones A, A1-30, AE, AH, AO, A99, V, V1-30 AND VE.

Certain areas not in Special Flood Hazard Areas may be protected by flood control structures

Boundaries of the floodways were computed at cross sections and interpolated between cross sections. The floodways were based on hydraulic considerations with regard to requirements of the Federal Emergency Management Agency.

Floodway widths in some areas may be too narrow to show to scale. Floodway widths are provided in the Flood Insurance Study Report.

Coastal base flood elevations apply only landward of the shoreline.

Elevations reference marks are described in the Flood Insurance Study Report

For adjoining map panels see separately printed Map Index

MAP REPOSITORY
Department of Public Works,
Wastewater Management Division
3840 York Street, Building G
Denver, Colorado 80205
(Maps available for reference only, not for distribution)

INITIAL IDENTIFICATION:
DECEMBER 28, 1975

FLOOD HAZARD BOUNDARY MAP REVISIONS:
APRIL 15, 1977

FLOOD INSURANCE RATE MAP EFFECTIVE:
APRIL 15, 1986

FLOOD INSURANCE RATE MAP REVISIONS:

Map revised, SEPTEMBER 28, 1990 to add base flood elevations, to change special flood hazard areas, to change base flood elevations, to reflect updated topographic information, to incorporate previously issued letters of map revision, and to update corporate limits

To determine if flood insurance is available, contact an insurance agent or call the National Flood Insurance Program at (800) 638-6620.

N

APPROXIMATE SCALE IN FEET

500 0 500

Figure 5-2. (Continued)

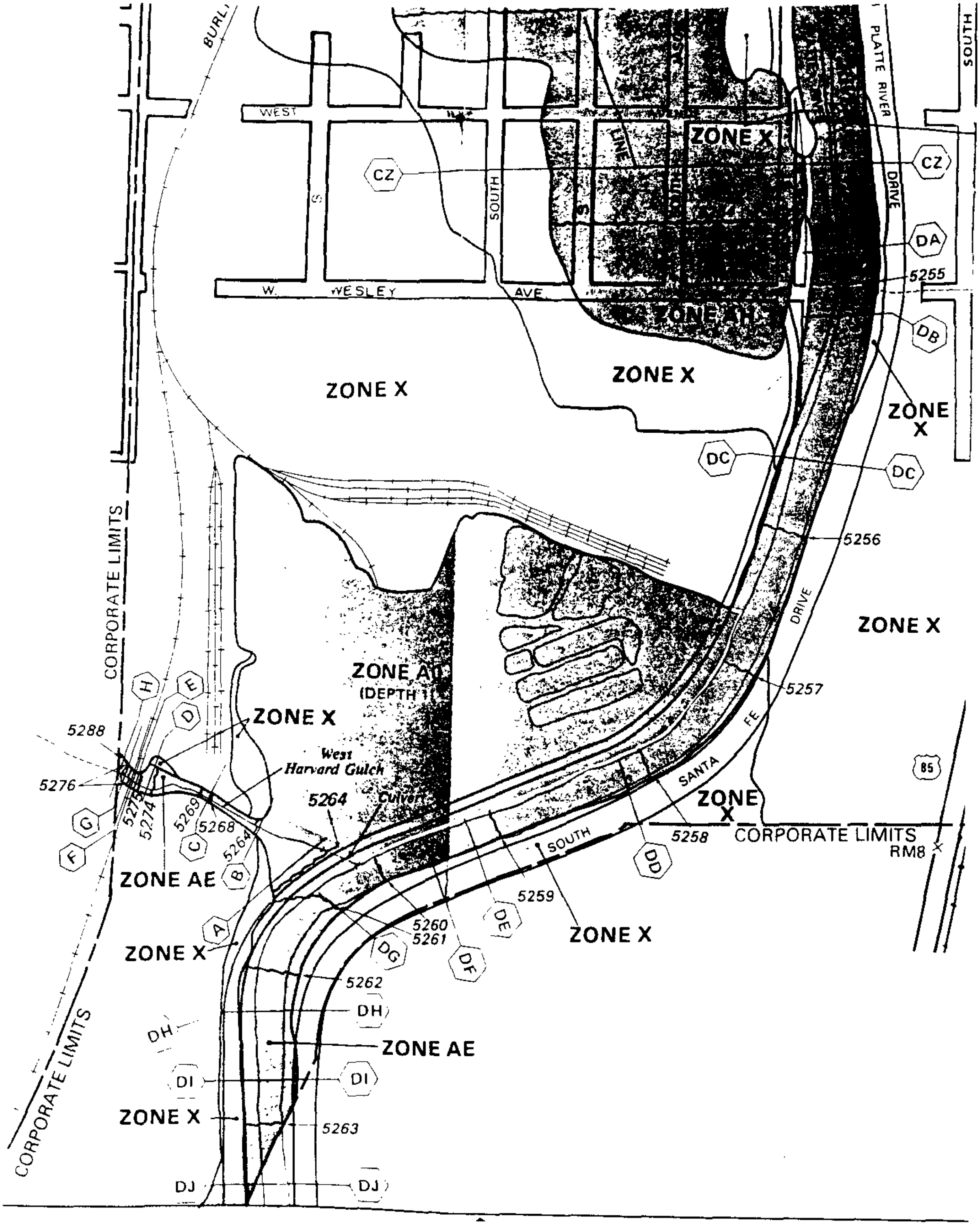
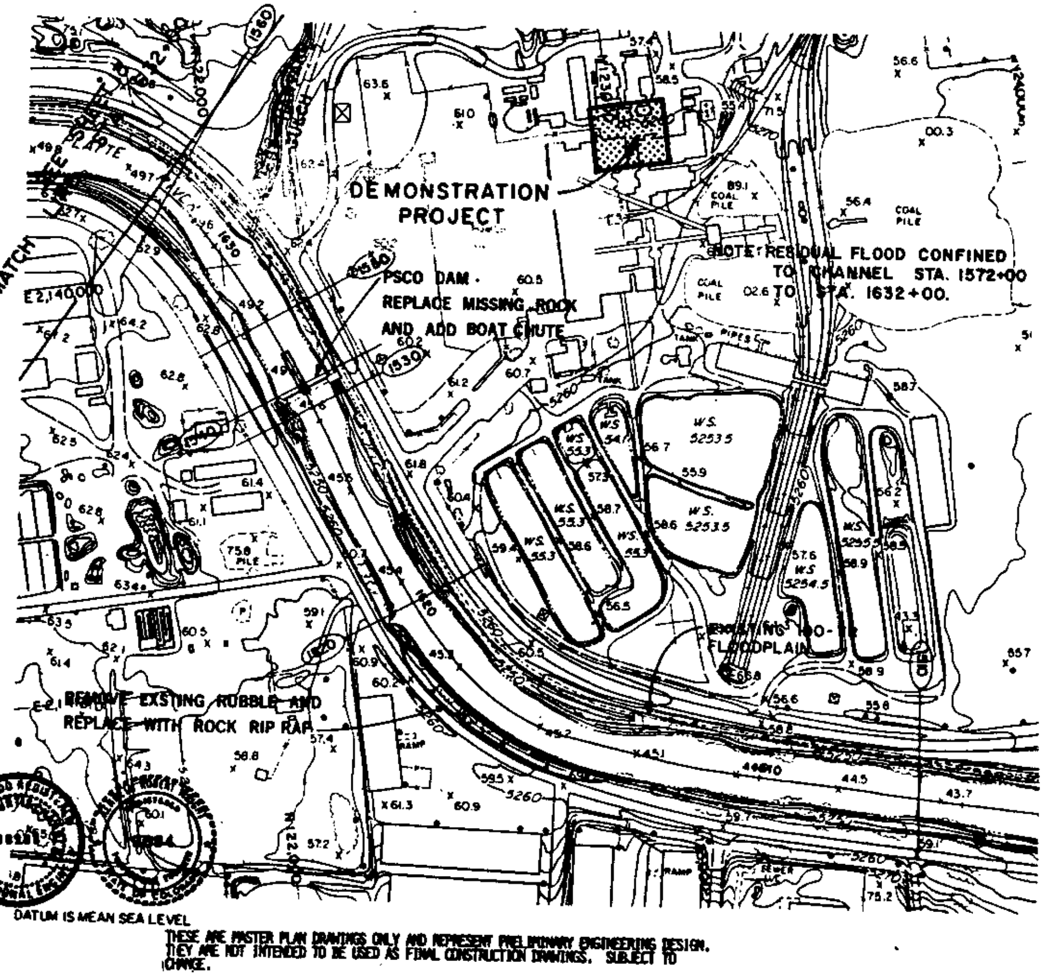
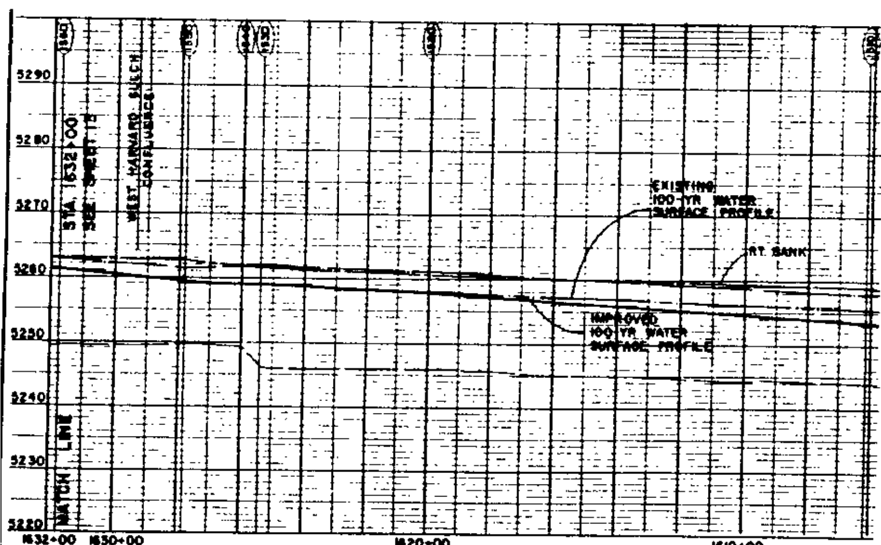


Figure 5-2. (Continued)

Zone Designations are Described on page 5-13.





KEY TO READING THIS EXCERPT OF THE FLOOD PLAN AND PROFILE:

This excerpt is a flood plan and profile of the 100-year flood for the area of Arapahoe Station. As indicated on the map above, the area of the proposed demonstration project is approximately opposite Station 1628+00 on the River (Cross-Section No. 1550). Using these coordinates on the side plan view (to the left), the elevation of the 100-year water surface profile can be determined. At this station and cross section, the 100-year flood elevation is 5259 ft. msl. Based on PSCC information, the ground-surface elevation at the demonstration project site is approximately 5262 ft. msl, three feet above the 100-year flood elevation. In any event, this excerpt shows that the improved floodplain in the vicinity of the plant is confined to the River channel.

URBAN DRAINAGE AND FLOOD CONTROL DISTRICT — PHASE B PLAN | MAJOR DRAINAGEWAY PLANNING — SOUTH PLATTE RIVER | PLAN AND PROFILE — STA. 1572+00 TO STA. 1632+00 | SHEET 14 OF 45

Figure 5-3. South Platte River, Flood Plan and Profile, Vicinity of Arapahoe Station

Source: Wright Water Engineers, Inc. Major Drainageway Planning South Platte River, Phase B-Volume I, Nov. 1985.

5.6.2 Wetlands

Executive Order 11990, Protection of Wetlands (May 24, 1977) requires federal agencies, such as the DOE, to consider the effects of proposed actions, such as the CCT-III program, on wetlands. The regulatory significance of the presence of wetlands at a project also relates to the dredge and fill permitting program of the USACE. The USACE issues permits for, among other things, the discharge of dredged or fill material into wetlands that are adjacent to "waters of the U.S." The State of Colorado does not implement a dredge and fill program.

According to the U.S. Fish and Wildlife Service National Wetlands Inventory System maps for Fort Logan and Englewood, Colorado, the pond system at Arapahoe Station (ash and polishing ponds) are designated as wetland areas of the Palustrine System. Generally, the Palustrine System groups vegetated wetlands more commonly called marshes, bogs, or ponds (Ref. 36). However, none of the elements of the integrated dry NO_x/SO_2 emission control system project are expected to impact these areas, and, in any event, no dredging or filling will be required. The area immediately affected by the project is not inundated by surface or ground water to support vegetative or aquatic life that requires saturated or seasonally saturated soil conditions for growth and reproduction of hydrophilic plants typically associated with wetlands.

5.7 State Environmental Impact Assessment Process

The State of Colorado has not enacted an environmental impact assessment process. Thus, no NEPA-type procedures are required at the state or local level.

6.0 LIST OF PREPARERS AND PROFESSIONAL QUALIFICATIONS

This Environmental Information Volume was prepared by Radian Corporation. The qualifications of the principal project members are summarized below. Appendix A consists of the resumes of these individuals.

The Project Director for preparation of this report is Leslie E. Barras. Ms. Barras is a staff attorney with six years of multi-media environmental experience at the federal, state, and local level. She directed the preparation of four EIVs during Round II of the Clean Coal program. Three of the projects were resolved as a memorandum-to-file, while the remaining project resulted in a Finding of No Significant Impact.

Mr. Gary M. Blythe prepared most of Section 4, Consequences of the Project. Mr. Blythe is a Principal Engineer in Radian's Process Engineering Department. His fifteen years of experience with Radian has primarily been in the area of dry flue gas desulfurization systems. He served as Radian's project director for a four-year pilot-scale evaluation of spray dryer technology for low-sulfur coal applications at the EPRI test facility at Arapahoe Station.

Ms. Lea Gore, an environmental engineer in Radian's Environmental Analysis Department, prepared portions of Sections 1-5.

The following PSCC personnel also provided input to this report:

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Denver, CO 80207
(303) 329-1113

7.0 REFERENCES AND CONTACTS

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11. National Bureau of Indian Affairs, (202) 343-1710.

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APPENDIX A

Personnel Resumes

LESLIE ELIZABETH BARRAS

EDUCATION:

J.D., Law, The University of Texas, Austin, TX, 1984.

M.P.A., Public Affairs, The University of Texas, Austin, TX, 1984.

B.A., Political Science, Texas A&M University, College Station, TX, 1980.

EXPERIENCE:

Attorney, Environmental Analysis Department, Radian Corporation, Austin, TX, 1987-Present.

Attorney, Lloyd, Gosselink, Ryan & Fowler, P.C., Austin, TX, 1984-1987 (environmental law practice).

Law Clerk, Booth, Lloyd & Simmons, P.C., Austin, TX, 1981-1984 (environmental law practice).

FIELDS OF EXPERIENCE:

Ms. Barras is familiar with the major federal and state environmental statutes relating to the regulation of hazardous waste, solid waste, water quality, air quality, and toxic substances. As an attorney in the Environmental Analysis Department, Ms. Barras' primary function is to ensure that Radian's permitting and compliance reports address applicable federal and state statutory and regulatory requirements.

Hazardous Waste

- Project Director or technical advisor for preparation of RCRA operating permit and permit amendment applications for petroleum refinery, chemical manufacturing, and commercial incineration facilities in Texas, Louisiana, and Delaware. Participation in responding to Notices of Deficiency and reviewing draft permits for oil refineries in Texas.

- Preparation of a post-closure permit application for a chemical manufacturer in Missouri.

- Preparation and review of surface impoundment closure plans for a number of facilities including an Air Force base in the southwestern U.S., an oil refinery in Alaska, and a synthetic chemicals manufacturing plant in the Midwest.

Wastewater

- Advisor for preparation of a state no-discharge permit for a project involving spray irrigation of an industrial effluent.

- Review and comment on proposed provisions of draft NPDES and state discharge permits for industrial clients.

- Advisor to industrial clients on effects of federal stormwater rules and NESHAP for benzene waste operations.

- Development of strategy for preparing and submitting new source review determinations for chemical manufacturing plants subject to categorical effluent limitations and guidelines.

Polychlorinated Biphenyls

- Project Director for preparation of TSCA application for an incinerator at a chemical manufacturing facility in Louisiana.

- Evaluation of PCB management practices at U.S. Air Force Air Training Command bases.

- Conduct of training sessions for a major oil company to explain PCB regulatory requirements to operating personnel.

- Technical advisor for preparation of a TSCA permit application for a PCB incinerator on the East Coast.

Regulatory Compliance Planning

- Preparation of a regulatory compliance plan for the two Texas sites proposed for location of the Superconducting Super Collider; the Waxahachie site was selected as the candidate locale by the U.S. Department of Energy (DOE) in November 1988. This task involved several months of intensive research on applicable local, state, and federal requirements, numerous contacts with regulatory officials of these agencies, and presentation of the plan to representatives of the DOE and its environmental contractor.

- Preparation of a regulatory compliance plan for a proposed coal/ municipal sewage sludge gasification facility in California.

- Conduct of a regulatory compliance assessment for a national pharmaceuticals company which relocated an eye-care product formulation plant in California to a central Texas location.

- Development of an environmental compliance document to enable a central Texas lime plant to understand the regulatory implications of burning hazardous waste-derived fuels for energy recovery.

- Environmental compliance forecasting and planning for a number of inorganic and organic chemical manufacturing plants on the Texas and Louisiana Gulf Coast.

Environmental Compliance and Real Estate Acquisition/Divestiture Auditing

- Direction of environmental, health, and safety audits for the exploration and production operations of a major U.S. oil company. Audited facilities are located in Texas, Kansas, New Mexico, Utah, Colorado, and California.

- Participation in environmental compliance evaluations for a number of U.S. Air Force Air Training Command bases in Texas, California, Arizona, and Oklahoma. These evaluations involve intensive, one-week assessments of Base compliance in a number of media areas, such as pesticides, waste, air, water, hazardous materials, polychlorinated biphenyls, noise, and radon.

- Participation in environmental, health, and safety compliance audits for a multinational corporation. Corporate divisions evaluated during the audit program included fluid technology (pump and valve manufacturing), automotive electric, hotels, defense contractors, electronics, and paper and pulp. Facilities are located in the U.S. and Mexico.

- Direction of, and participation in, an environmental compliance assessment of the wastewater, waste, hazard communication, PCB, air quality, SPCC, USTs, and EPCRA programs of an electric utility in south-central Texas.

- Participation in audits for real estate transactions involving a waste reclamation facility, a cogeneration facility, and a petrochemical plant on the Texas Gulf Coast, a warehouse facility in the Dallas-Fort Worth area, and a commercial office building in central Texas.

Environmental Training

- Development and implementation of an environmental awareness training program for a major oil company. The program covered federal and state laws relating to corporate liability for environmental violations, water quality, air quality, drinking water, hazardous waste, pesticides, toxic substances, emergency planning and community right-to-know, underground storage tanks, hazard communication programs, and hazardous worker operational training. Subsequent expansion of the program included Canadian training sessions for the company's oil and gas operations in Alberta, British Columbia, and Saskatchewan.

- Presentation of an informational program to a national transportation firm on the effect of federal stormwater rules on its operations.

- Participation in development of an environmental manual for the operating managers and personnel of a national can manufacturing company.

NEPA Documentational Environmental Assessments

- Direction of and participation in preparing five NEPA environmental information documents for electric utility projects in Florida, Georgia, and Colorado which were funded under the U.S. Department of Energy Innovative Clean Coal Program.

- Preparation of the cultural resource requirements for the environmental information volume for the Texas Superconducting Super Collider site.

PROFESSIONAL SOCIETIES:

State Bar of Texas, Natural Resources and Environmental Law Section

PUBLICATIONS:

Barras, L. "Environmental Compliance Assessments at Federal Installations." Presented at American Defense Preparedness Association Conference at Atlanta, April 18-20, 1990.

Bell, R. and L. Barras. "On-Site Versus Off-Site Incineration to Remediate a Surface Impoundment." Presented at International Conference on Incineration of Hazardous, Radioactive, and Mixed Wastes, University of California at Irvine, May 3-6, 1988.

GARY M. BLYTHE

EDUCATION:

B.S., Chemical Engineering, The University of Texas at Austin, Austin, TX, 1974.

EXPERIENCE:

Principal Engineer and Group Leader, Radian Corporation, Austin, TX, 1988-Present.

Senior Staff Engineer and Group Leader, Radian Corporation, Austin, TX, 1984-1987.

Senior Engineer, Radian Corporation, Austin, TX, 1979-1983.

Staff Engineer, Radian Corporation, Austin, TX, 1977-1979.

Engineer, Radian Corporation, Austin, TX, 1975-1977.

Engineer, El Paso Natural Gas Company, 1974-1975.

FIELDS OF EXPERIENCE:

Mr. Blythe is a Principal Engineer in Radian's Process Engineering Department. He primarily works on programs related to dry flue gas desulfurization (FGD) systems. Mr. Blythe's experience in this and other areas is described below.

Dry Flue Gas Desulfurization

Mr. Blythe currently serves as Radian's Project Director for three on-going pilot-scale research projects related to dry FGD processes. One is a 4-MW-scale study of spray dryer FGD for high sulfur coal applications, primarily with a pulse-jet fabric filter particulate collection device, being conducted at the EPRI High Sulfur Test Center in New York. The second is a 10-MW-scale research program being conducted at TVA's Shawnee Test Facility. This project is evaluating spray dryer FGD technology for high sulfur coal retrofit applications, where an existing electrostatic precipitator is intended to be used for particulate control. The third is also being conducted at a 4-MW scale at the EPRI High Sulfur Test Center. This research project is evaluating the technical capabilities of the EPRI HYPAS process, which involves flue gas humidification and lime injection for SO_2 control downstream of an existing low-efficiency ESP but upstream of a retrofit pulse-jet fabric filter. In all of these projects, Mr. Blythe directs the efforts of associated Radian technical staff members, and of sub-contractor personnel. Furthermore, Mr. Blythe is responsible for test planning, data review, reporting, client project manager communications, and coordinating contractual and invoicing efforts.

In previous dry FGD projects, Mr. Blythe has:

- Been Radian's Project Director for a four-year pilot-scale evaluation of spray dryer technology for low sulfur coal applications, conducted at the EPRI Arapahoe Test Facility in Denver, Colorado.

- Served as Project Director and lead on-site engineer for a full-scale evaluation of spray dryer FGD technology conducted at the Northern States Power Company Riverside Station.

- Been a project team member and principal author of the final report for a full-scale demonstration of a dry sodium injection FGD system retrofit to 100 MW of the City of Colorado Springs R.D. Nixon station.

- Served as Project Director and lead on-site engineer for a full-scale demonstration of furnace limestone injection on a low-rank coal-fired utility boiler.

- Designed, procurred, installed, and started-up a temporary hydrated lime injection system for an acid gas control test program at an operating municipal solid waste incinerator.

- Served as Project Director for a 1-MW evaluation of hydrated lime injection and in-duct spray drying as potential retrofit FGD technologies for utility application with either electrostatic precipitator or fabric filter particulate control devices.

- Completed the initial process design for the spray dryer FGD system installed at the EPRI High Sulfur Test Center in New York.

- Served as Project Director, on-site engineer, or principal investigator on a number of other dry-FGD-related projects since 1977.

Wet FGD Systems

- On-site engineer during testing of a demonstration-scale forced oxidation system installed by a major FGD vendor on a wet limestone scrubber at the TVA Widow's Creek station.

- On-site engineer for a full-scale test of the upgrading of a venturi-type particulate control scrubber by the addition of lime slurry to effect simultaneous SO_2 removal.

- Wrote the section on FGD process chemistry for the EPRI Limestone Data Book.

- Conducted a study to establish the scope of the wet scrubbing pilot facilities that have since been constructed at the EPRI High Sulfur Test Center in New York.

NO_x Control

- Served as on-site engineer for pilot-scale development of a proprietary wet NO_x scrubbing process for a large Western utility.

Particulate Control

- In previously-described research programs, has participated in the start-up, operation, and/or evaluation of pilot- to full-scale reverse-gas fabric filters, a shake-deflate fabric filter, pulse-jet fabric filter, and electrostatic precipitators which effect particulate control downstream of dry FGD processes.

- Served as Task Leader for data evaluation and reporting for a study to quantify bag fabric aging effects on the performance of a two-module 10-MW pilot reverse gas fabric filter at a large Western utility coal fired power plant.

- Served as a third-party reviewer of plans by a cement company to implement process changes and upgrade existing particulate control equipment to avoid permit violations.

FGD Reagent Preparation

- In previously-described research progarms, has participated in the start-up, operation, and evaluation of pilot- to full-scale lime slakers of virtually all commercially-available types, including detention, paste, ball mill, and attrition mill slakers.

- Major contributor to an EPRI-funded program to study the effects of equipment type and operating conditions on the reactivity of both lime and limestone slurries prepared for use in wet and dry FGD systems.

PROFESSIONAL SOCIETIES

American Institute of Chemical Engineers

PUBLICATIONS

Fuchs, M.R., G.M. Blythe, et al. Full-Scale Demonstration of a Utility Dry Sodium Injection FGD Facility. EPRI GS6860, Research Project 1682-6. Final Report. Radian Corporation, Austin, TX, July 1990.

Barton, R.A., C.W. Dawson, T.A. Burnett, G.A. Hollinden, K.L. Wertz, G.M. Blythe, and R.G. Rhudy. "SO_2 Removal Performance Improvements by Chloride Addition at the TVA 10-MW Spray Dryer/ESP Pilot Plant." Presented at the 1990 SO_2 Control Symposium, New Orleans, LA, May 8-11, 1990.

Blythe, G.M., et al. "Results of EPRI High Sulfur Test Center Spray Dryer/Pulse-Jet Fabric Filter Pilot Tests." Presented at the 1990 SO_2 Control Symposium, New Orleans, LA, May 8-11, 1990.

Blythe, G.M., et al. "Results from EPRI High Sulfur Spray Dryer Pilot Tests." Presented at the First Combined FGD and Dry SO_2 Control Symposium, St. Louis, MO, October 25-28, 1988.

Brown, C.A. and G.M. Blythe, et al. "Results from the TVA 10-MW Spray Dryer/ESP Evaluation." Presented at the First Combined FGD and Dry SO_2 Control Symposium, St. Louis, MO, October 25-28, 1988.

Blythe, G.M., et al. "Results From the First Year of Operation of the EPRI High-Sulfur Spray Dryer/Fabric Filter Pilot Unit." Paper presented at the APCA 1988 Annual Meeting, Dallas, TX, June 19-24, 1988.

Fuchs, M.R., G.M. Blythe, et al. Full-Scale Demonstration of a Utility Dry Sodium Injection FGD Facility. Revised Draft Final Report, EPRI Research Project 1682-6, Radian Corporation, Austin, TX, April, 1988.

Brown, C.A., G.M. Blythe, et al. "Spray Drying/Electrostatic Precipitator Retrofit on High Sulfur Coal: Results of 10-MW Pilot Tests." Paper presented at the American Power Conference, Chicago, IL, April 18-22, 1988.

Blythe, Gary, et al. "EPRI High-Sulfur Spray Dryer/Fabric Filter Pilot Results." Paper presented at the EPA/EPRI sponsored Seventh Symposium on the Transfer and Utilization of Particulate Control Technology, Nashville, TN, March 22-25, 1988.

Blythe, Gary, et al. "Pilot-Scale Studies of SO_2 Removal by the Addition of Calcium-Based Sorbents Upstream of a Particulate Control Device." Paper presented at the EPA/EPRI Co-sponsored Tenth Symposium on Flue Gas Desulfurization, Atlanta, GA, November 18-21, 1986.

Brown, C.A., G.M. Blythe, and L. Lepovitz. "Design and Selection Considerations for Spray Dryer Based Flue Gas Desulfurization Systems." Report prepared for the U.S. EPA and the Naval Surface Weapons Center in Dahlgren, Virginia. Radian Corporation, Austin, TX, September 30, 1986.

Blythe, G., et al. "EPRI Pilot Testing of SO_2 Removal by Calcium Injection Upstream of a Particulate Control Device." Paper presented at the 1986 Joint Symposium on Dry SO_2 and Simultaneous SO_2/NO_x Control Technologies, Raleigh, NC, June 2-6, 1986.

Rhudy, R.G. and G.M. Blythe. "Power Plant Wastewater Reuse in Spray Dryer FGD Systems: Pilot and Full-Scale Results." Paper presented at the EPRI Symposium on Advances in Fossil Power Plant Water Management, Orlando, FL, February, 1986.

Blythe, G.M., and R.G. Rhudy. "Fabric Filter Interactions in Spray Dryer Based FGD." Paper presented at the Third Conference on Fabric Filter Technology for Coal-Fired Power Plants, Scottsdale, AZ, November 19-21, 1985.

Blythe, Gary et al. "SO_2 Removal by Calcium Injection Upstream of a Particulate Control Device" Paper presented at the Third Conference on Fabric Filter Technology for Coal-Fired Power Plants, Scottsdale, AZ, November 19-21, 1985.

Rhudy, R.G. and G.M. Blythe. "Recent Results from the EPRI 2-1/2 MW Spray Dryer Pilot Plant." Paper presented at the EPA/EPRI Symposium on Flue Gas Desulfurization, Cincinnati, OH, June 4-7, 1985.

Blythe, G.M. et al. Evaluation of a 2.5 MW Spray Dryer/Fabric Filter SO_2 Removal System. EPRI CS-3953, Research Project 1870-3 Interim Report, Radian Corporation, Austin, TX, May 1985.

Blythe, G.M. et al. Field Evaluation of a Utility Spray Dryer System. EPRI CS-3954, Research Project 1870-4. Final Report, Radian Corporation, Austin, TX, May 1985.

Rhudy, R.G., and G.M. Blythe. "Fabric Filter Operation Downstream of a Spray Dryer: Pilot and Full-Scale Results." Paper presented at the EPA/EPRI Joint Particulate Control Symposium, Kansas City, KS, August 27-30, 1984.

Blythe, G.M. and R.G. Rhudy. "EPRI Spray Dryer/Baghouse Pilot Plant Status and Results." Paper presented at the EPA/EPRI Symposium on Flue Gas Desulfurization, New Orleans, LA, November 1-4, 1983.

Blythe, G.M., and R.G. Rhudy. "Field Evaluation of a Utility Dry FGD System." Paper presented at the EPA/EPRI Symposium on Flue Gas Desulfurization, New Orleans, LA, November 1-4, 1983.

Colley, J.D., and G.M. Blythe. "Status and Results of EPRI Lime FGD Reagent Preparation Studies." Paper presented at the National Lime Association

Conference on Effective Use of Lime for Flue Gas Desulfurization, Denver, CO, September 27-28, 1983.

Rhudy, R.G. and G.M. Blythe. "EPRI Spray Dryer/Baghouse Pilot Plant Status and Results." Paper presented at the Second Conference on Fabric Filter Technology for Coal-Fired Power Plants, Denver, CO, March 22-24, 1983.

Blythe, G.M. Dry Limestone Injection Test at a Low-Rank Coal-Fired Power Plant. Final Report. DOE/FC/10200-T5 (DEW83005164). Work Performed Under Contract No. AC18-80FC10200. Radian Corporation, Austin, TX, November 23, 1982.

Blythe, G.M., et al. "EPRI Spray Drying Pilot Plant Status and Results." Paper presented at the joint EPA/EPRI Symposium on Flue Gas Desulfurization, Hollywood, FL, May 17-20, 1982.

Blythe, G.M., J.C. Dickerman and M.E. Kelly. "Survey of Dry SO_2 Control Systems." EPA-600/7-80-030. Radian Corporation, (NTIS PB 80166853), Durham, NC, February 1980.

LEA LYNN GORE

EDUCATION:

B.S., Civil Engineering, Texas A&M University, College Station, TX, 1989.

EXPERIENCE:

Associate Engineer/Scientist, Environmental Analysis Department, Radian Corporation, Austin, TX, 1990-Present.

Environmental Co-op Student, ARCO Chemical Company/Bayport, Pasadena, TX, 1987-1988.

FIELDS OF EXPERIENCE:

As environmental co-op student at ARCO-Chemical Company, Ms. Gore was responsible for ensuring compliance with federal, state, and local regulations for hazardous waste, wastewater, stormwater, and air emissions. She also coordinated and assisted projects for hazardous waste tank certifications, RCRA Part B permit applications, and internal environmental audits. She established a database and monitoring program for fugitive emissions and prepared a manual for assistance in disposal of all hazardous and non-hazardous waste.

HONORARY/PROFESSIONAL SOCIETIES:

American Society of Civil Engineers
Tau Beta Pi
Chi Epsilon