SITE CERTIFICATION APPLICATION

ORLANDO UTILITIES COMMISSION
CURTIS H. STANTON ENERGY CENTER
UNIT 1

VOLUME 2

No. 1

ORLANDO UTILITIES COMMISSION

CURTIS H. STANTON ENERGY CENTER
UNIT 1

SITE CERTIFICATION APPLICATION

VOLUME 2

ORLANDO UTILITIES COMMISSION

CURTIS H. STANTON ENERGY CENTER
UNIT 1

SITE CERTIFICATION APPLICATION

VOLUME 2

APPLICATION FOR CERTIFICATION OF A PROPOSED
ELECTRICAL POWER GENERATING PLANT SITE

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3.0 THE PLANT

3.0 THE PLANT

3.1 EXTERNAL APPEARANCE

The initial development phase of the Curtis H. Stanton Energy Center will include Unit 1, a 460 gross-415 net MW, coal-fueled steam/electric generator. Unit 1 facilities will also include an electrostatic precipitator, sulfur dioxide removal equipment, and a chimney. Several other facilities will be constructed during initial development to serve ultimate development of 4 units at the site. These include the cooling tower makeup water supply storage pond, the coal pile runoff pond, the recycle basin, the active combustion waste area runoff pond, and the associated onsite facilities. The coal storage area and associated coal-handling facilities will be initially constructed for two units with expansion to four-unit capacity when Unit 3 is constructed.

Artist's renditions of the Stanton Energy Center with one unit and with four units have been prepared and are included as Figures 3.1-1 and 3.1-2.

3.1.1 Plant Profile

A general plant profile of the Unit 1 central generating facilities is shown in Figure 3.1-3. This profile is based on the elevations of the various facilities as viewed from the north looking south. All structures shown by the profile except the Administration and Plant Services Buildings will be totally enclosed with base walls of precast concrete and upper walls of steel panels with bonded coatings. The Administration and Plant Services Building will have a brick veneer exterior. The elevations and dimensions shown in Figure 3.1-3 are preliminary and may change as detailed engineering design proceeds.

3.1.2 Site Arrangement

Initial development of the Stanton Energy Center will consist of Unit 1 and associated facilities. As shown by Figure 3.1-4, certain facilities will be initially developed to accommodate ultimate site capacity of

4 units. The ultimate site capacity is 4 units as shown in Figure 3.1-5. The location, orientation, and arrangement of the units and associated facilities were based on the locations of nest-cavity trees of the red-cockaded woodpecker, existing wetland areas, and relationships among the less compatible project facilities. The solid waste disposal area was placed along the western boundary of the site because of the existing high surface elevations which would allow the use of the area as a source of fill material, because of the lack of nest-cavity trees or significant wetlands, and because of the presence of an existing sanitary landfill on adjacent property to the west. The railroad loop logically was placed along the south side of the complex since the railroad spur from Orlando approaches from the south.

The initial development of the site will involve the use of 960 acres |4
of land exclusively for Unit 1 and associated facilities. Complete development to the ultimate site capacity of 4 units will require the exclusive use of about 1,100 acres of the site. The remaining 2,180 acres will be |4 | 5
maintained as a buffer zone and portions will provide foraging habitat for the red-cockaded woodpecker.

3.1.3 Release Points

The Stanton Energy Center is designed so no wastewater discharges to surface waters will be necessary. Surface runoff from undisturbed portions of the site will follow existing natural drainage patterns. Surface runoff from the coal storage pile and the active solid waste storage area will be collected in lined ponds and transferred to a lined recycle basin for use in the plant. Surface runoff from the developed portions of the central plant complex will be routed to the makeup water supply storage pond which will be unlined to promote percolation. Part of the cooling tower blowdown | 5
and central plant complex drainage will be directed to the recycle basin for use in the flue gas desulfurization equipment. The remainder of the

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blowdown and plant drainage in excess of plant needs will be pumped to the Orange County Easterly Subregional Wastewater Treatment Plant for treatment and separate disposal. A detailed description of the water supply, uses, and management is presented in Section 3.3. RFM-1

Combustion gas wastes will be released from two sources associated with Unit 1. The major source will be the combustion of coal in the steam generator and the release point will be the 550-foot tall chimney. The oil-fired auxiliary boiler to be used for unit startup will also generate combustion gases. The release point for these gaseous wastes will be the auxiliary boiler chimney to be located on the roof of the Administration and Plant Services Building.

With expansion to the ultimate site capacity of 4 units, 3 major release points for combustion gas wastes will be added; the chimneys to be installed with each unit. No additional auxiliary boilers will be required.

Fugitive dust release points for one unit will consist of the coal storage pile, the stacker/reclaimer, conveyor systems, transfer houses, unit train unloading facility, fly ash storage silo, lime handling equipment and storage silo, and the limestone storage pile and handling equipment. 5
Detailed descriptions of these fugitive dust release points are provided in Section 3.2, Section 3.7, and Section 3.9.

Fugitive dust release points for the 4-unit development will be similar to 1 unit, but will involve larger quantities of coal and limestone, additional conveyors for the additional units, and additional fly ash storage silos.

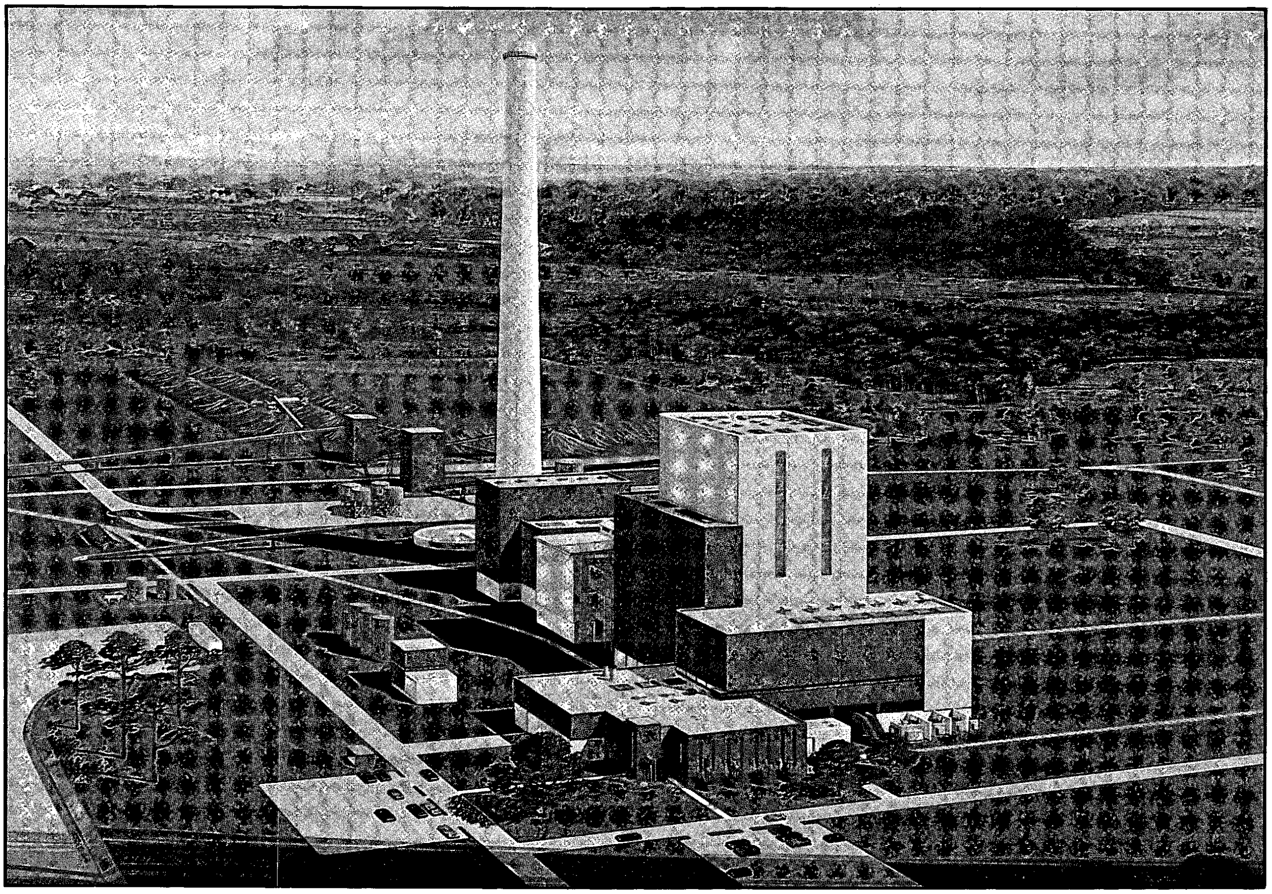

FIGURE 3.1-1. ARTIST'S RENDITION OF CURTIS H. STANTON ENERGY CENTER - 1 UNIT

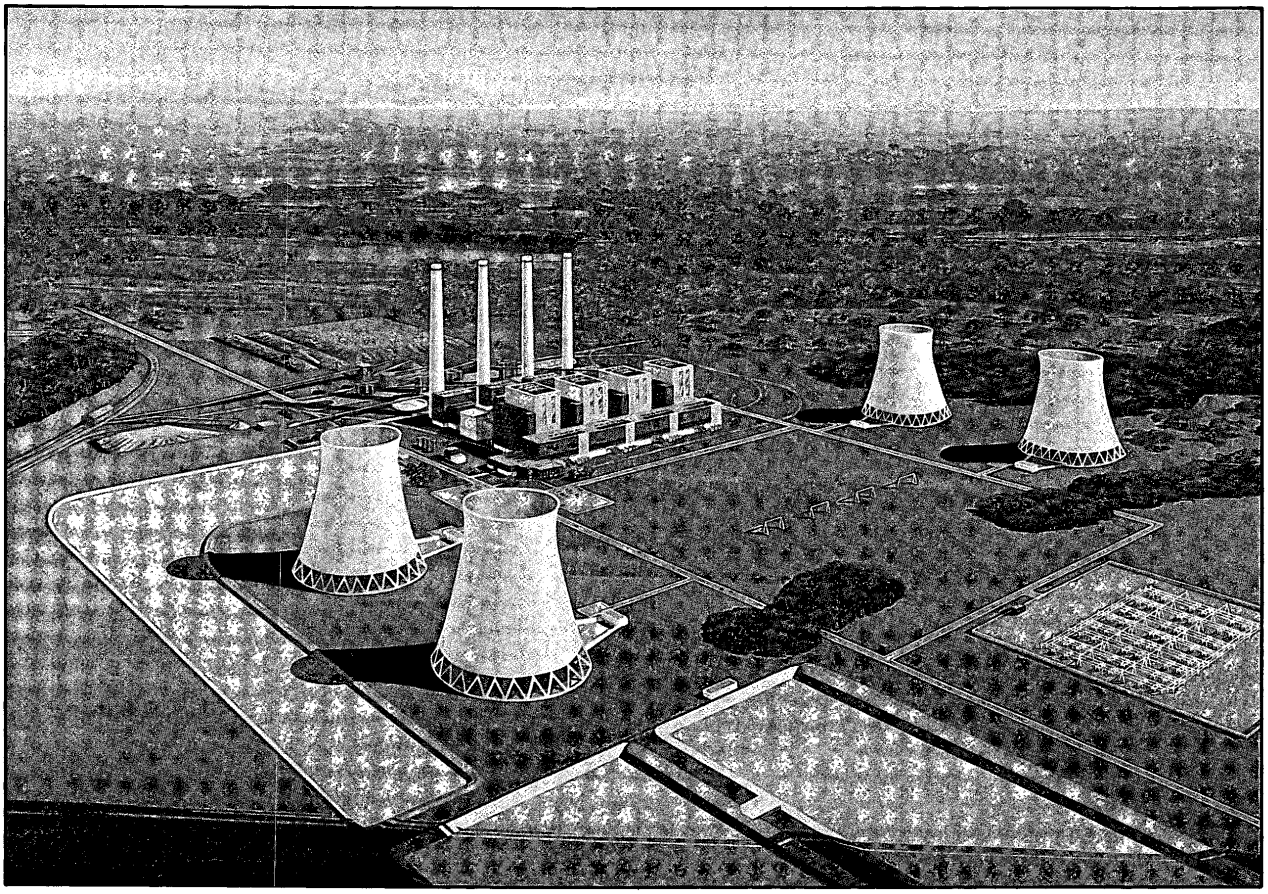

FIGURE 3.1-2. ARTIST'S RENDITION OF CURTIS H. STANTON ENERGY CENTER - 4 UNITS

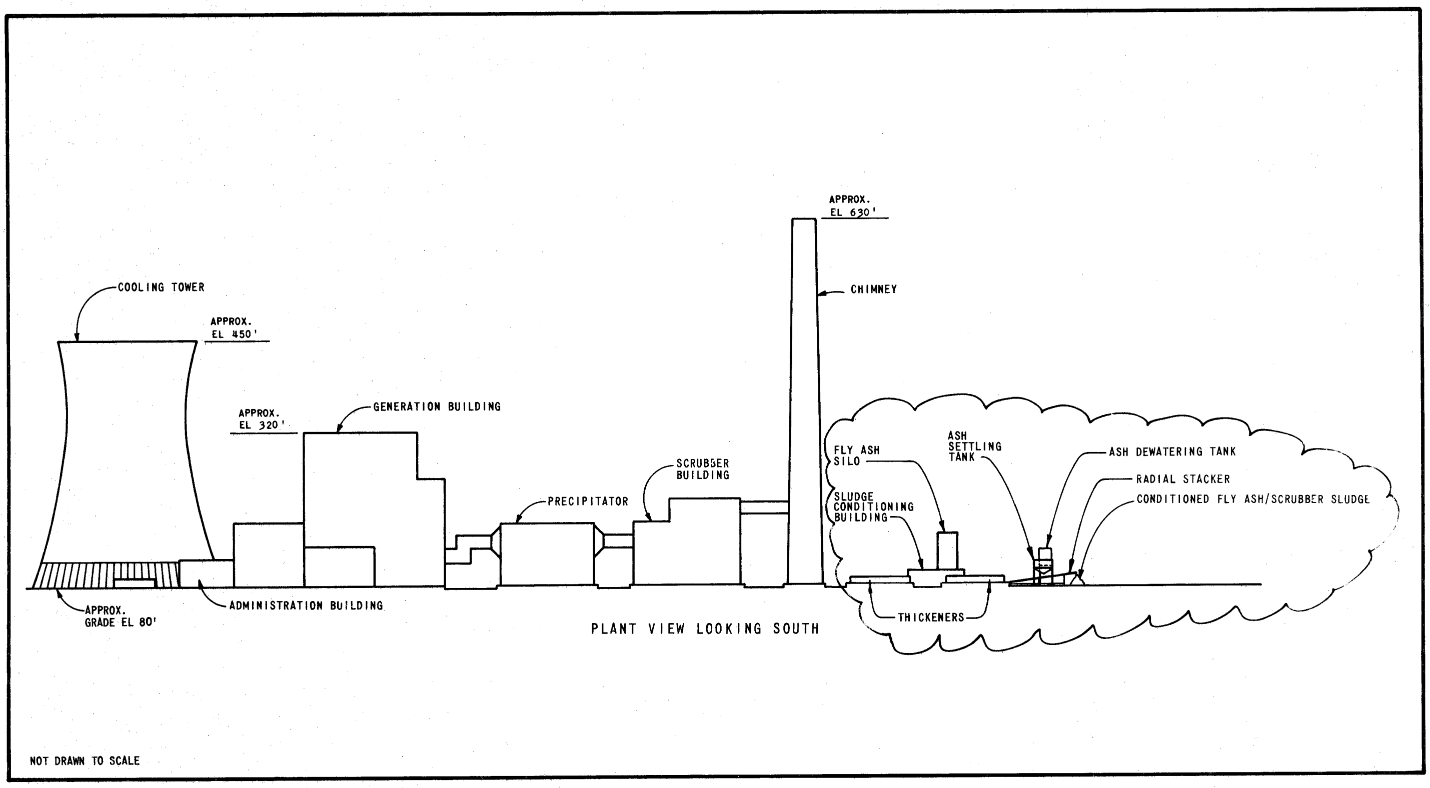

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FIGURE 3.1-3. GENERATION
FACILITIES PROFILE

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3.2 FUEL

3.2.1 Fuel Types and Qualities

The primary fuel for the Stanton Energy Center will be coal. Although coal supply contracts for Unit 1 have not been finalized, it is anticipated that bituminous coal from the Appalachian coal fields or the Illinois Basin will be used. It is also anticipated that the coal supplies for the Stanton Energy Center may change as future units are added. To provide the necessary design flexibility to accommodate the use of coals with a wide range of properties, three typical coals with differing properties were selected as design bases. The design-basis coal for the steam generator is a washed Illinois Basin coal; the design-basis coal for the particulate removal system is a washed Appalachian coal; and the design-basis coal for the flue gas desulfurization system is an unwashed Illinois Basin coal. Table 3.2-1 presents the typical and ranges of properties of these three coals. Designing these three major components to each handle a "worst case" design-basis coal will provide the overall system design flexibility to burn any coal with properties within the ranges illustrated in Table 3.2-1.

The importance of design flexibility in relation to coal supplies and their properties is illustrated by the following factors.

(1) Specific coal supplies for Unit 1 are not known.

   (a) Coal supply contract for Unit 1 initial supply has not been completed.

   (b) Unit 1 coal supply may change with the renegotiation of coal supply contracts and the addition of future units.

(2) Coal storage and handling areas and facilities for Unit 1 will be designed and constructed to provide for possible segregation of coal supplies for individual units. However, the flexibility of Unit 1 to burn a wide range of coals will reduce the probability that such segregation will be necessary.

The steam generator will be started with No. 6 fuel oil. During periods of low load operation, No. 6 fuel oil will also be used for flame stabilization. The auxiliary boiler, emergency generator, emergency fire pumps, and mobile coal handling and solid waste disposal equipment will use No. 2 fuel oil; and other vehicles will use gasoline or diesel fuel.

3.2.2 Fuel Quantities

Based on a heating value range of 11,000 to 13,500 Btu/lb, the maximum coal consumption rate will be 154 to 191 tons/hr. At a 64.6 per cent load factor during the early years of the plant life, the annual coal consumption for Unit 1 would be 900,000 to 1,100,000 tons per year. At lifetime capacity factor of 53.6 per cent, annual coal consumption for Unit 1 would be 750,000 to 910,000 tons per year.

It is estimated that Unit 1 will experience 10 cold and 20 hot startups per year during the initial years of operation. This will require 80,000 gallons of No. 6 fuel oil per year. The unit may be used as a cycling unit during the later years of its life. Based on 200 startups per year (50 cold and 150 hot) the unit would consume 310,000 gallons of No. 6 fuel oil per year.

The auxiliary boiler will be required during cold and hot startup of Unit 1. Based on 10 cold and 20 hot startups per year, the annual fuel consumption will be 57,000 gallons per year. When Unit 2 begins operation, it is expected that the auxiliary boiler will be used only during rarely occurring conditions when one unit is down and the other unit is starting up.

3.2.3 Fuel Transportation

Coal will be transported to the plant site by unit trains with 70 to 100 cars of 100-tons capacity. Two to three trains per week will be required to supply the coal required for Unit 1. Train turnaround time will be approximately 6 days. The coal will be transported to the site from the Seaboard Coast Line Railroad (SCL) on a rail spur that connects to SCL south of Orlando, Florida and runs east parallel to the Bee Line Expressway and then north into the site. A description of the rail spur is given in Section 3.9.

Fuel oil will be shipped to the plant by truck or rail, depending on the supplier. Diesel fuel and gasoline will be transported to the site by truck.

3.2.4 Coal Handling and Storage

The coal handling system will consist of unloading, stocking, reclaiming, and long term reserve storage facilities. Figure 3.2-1 shows a schematic of the coal handling process, Figure 3.2-2 shows the layout of the coal handling facilities and Figure 3.2-3 shows a perspective of the coal handling facilities.

The unit train unloading will employ an enclosed bottom-dumping type facility designed for rapid-discharge bottom-dump cars. Unloading of the rapid-discharge bottom-dump cars will be accomplished by moving the train across a receiving hopper at a slow speed (approximately 1/3 mph) and automatically dumping the contents of the rail car as it passes over the receiving hoppers. Cars will be unloaded at a rate of 35 cars per hour. The entire operation of unloading a complete unit train from the time it enters the site until it leaves for the mine will take approximately 4 hours.

As the train is being unloaded, the coal will be conveyed to the transfer house where it can be conveyed to the crusher building directly, to the emergency stockout, or to the stacker/reclaimer for stockout and reuse. A normal mode of operation would be to divert enough coal directly to the crusher building (and subsequently to the plant) to top off the coal silos and stock the remainder with the stacker/reclaimer to be reclaimed later as necessary.

The stacker/reclaimer system will consist of a bucket-wheel-short boom trencher-type equipment which will travel on a track. The stacker/reclaimer will stock active reserve coal on both sides of the track allowing a reclaim capacity of approximately 12,000 tons per side as a minimum.

Long term inactive reserve storage will be a pile of approximately 400,000 tons located north of the active storage pile. An emergency storage and reclaim pile located north of the transfer building will be available for use as surge capacity when unloading a train or reclaim activities, in the event the stacker/reclaimer is out of service.

Coal conveyed to the crusher and on to the steam generator building will supply unit coal silos located directly above the coal pulverizers. Coal scales will be provided for inventory control and coal sampling equipment will be provided for monitoring coal quality.

The coal handling, unloading, and stockout systems are capable of supplying the coal for the ultimate four unit development. Initial facilities will be capable of handling two units. Facilities required to be added for Units 3 and 4 consist of extension of active storage area (berm and stacker reclaimer track), and addition of a crusher house and associated conveyors, scales, and sampling equipment for Units 3 and 4.

Fugitive dust associated with the handling of coal will be controlled with conveyor enclosures, water and chemical sprays, compaction, telescopic chute, and bag filters. All coal conveyors not underground or within buildings will be constructed with enclosures consisting of a roof and sides with a steel-grate floor except for those sections which pass over other plant facilities such as roads, buildings, and work areas. Such sections will be constructed with solid floors to intercept coal which RFM-1
falls from the conveyor belt. The transfer and cascade conveyors between the plant transfer hopper and the coal silos within the generation building will be totally enclosed and connected to the bag filter system which serves the coal silos. Table 3.2-2 lists the release points and control methods. Estimated emission levels of fugitive coal dust for the release points are given in Section 5.5.

3.2.5 Fuel Oil Storage and Handling

The fuel oil, as received, will be unloaded and pumped to storage tanks. No. 6 fuel oil will be stored in a 250,000 gallon tank and No. 2 fuel oil will be stored in a 41,000 gallon tank. The storage tanks will be located south of the main generating facilities. A spill-prevention dike will be located around the tanks. The area inside the dike will be lined. The supply to the steam generator igniters and auxiliary boiler in the main plant buildings will be by pumps located at the storage tank facility.

3.2.6 Alternate Fuel Types

No special design features have been included in the design of Unit 1 to allow burning of alternate fuels. Consideration has been included in the site layout for future reception and storage of slurry coal from a pipeline entering the site from the north. In addition, the site layout has considered the future addition of refuse receiving, preparation, conveying, and burning in future units.

TABLE 3.2-1. SUMMARY OF DESIGN COAL PROPERTIES

	Steam Generator Illinois Basin Coal Washed		Particulate Removal Appalachian Coal Washed		Desulfurization Illinois Basin Coal Not Washed	
	Typical	Range	Typical	Range	Typical	Range
Proximate Analysis						
Moisture (%)	8.00	7.0-9.0	5.0	4.5-5.5	7.5	6.5-8.5
Ash (%)	7.80	7.0-8.5	10.0	8.5-11.0	16.5	15.5-18.5
Volatile (%)	39.20	38.0-40.4	28.4	28.2-29.2	35.4	33.5-37.0
Fixed Carbon (%)	45.00	43.0-47.0	56.6	54.3-58.4	40.6	39.0-42.0
Heating Value (Btu/lb)	12,400	12,200-12,600	13,000	12,900-13,150	11,000	10,900-11,300
Sulfur (%)	2.8	2.5-3.1	0.77	0.71-0.82	3.85	3.5-4.0
Sulfur Forms						
Pyritic (%)	1.30	1.20-1.40	0.22	0.20-0.24	2.25	2.0-2.5
Organic (%)	1.65	1.55-1.77	0.54	0.52-0.56	1.83	1.70-1.95
Sulfate (%)	0.09	0.07-0.11	0.00		0.08	0.06-0.10
Reduction of SO_2 by Washing (%)	35.48		--		-0-	
Ultimate Analysis %						
Moisture	8.0	7.0-9.0	5.00	4.5-5.5	7.5	6.5-8.5
Carbon	68.73	66.0-70.0	74.09	73.0-78.0	60.15	58.0-62.0
Hydrogen	4.86	4.5-5.1	4.71	4.65-4.90	4.20	4.0-4.4
Nitrogen	1.14	1.0-1.3	1.26	1.24-1.49	1.14	1.0-1.3
Chlorine	0.16	0.12-0.20	0.13	0.02-0.15	0.12	0.08-0.16
Sulfur	2.80	2.2-3.4	0.76	0.71-0.82	3.85	3.5-4.0
Ash	7.8	7.0-8.5	10.00	8.5-11.0	16.50	15.5-18.5
Oxygen	6.51	6.0-7.0	4.04	2.38-4.04	6.54	5.5-7.0
Mineral Analysis of Ash (%)						
Phosphate Pentoxide, (P_2O_5)	0.12	0.08-0.16	0.30	0.25-0.45	0.18	0.15-0.20
Silica, (SiO_2)	49.67	48.0-51.0	47.94	46.09-48.77	43.66	42.0-45.0
Ferric Oxide, (Fe_2O_3)	19.09	17.5-20.5	9.39	8.60-11.82	21.21	20.0-22.4
Alumina, (Al_2O_3)	20.25	19.0-21.5	28.95	27.5-30.36	16.17	15.5-17.0
Titania, (TiO_2)	0.98	0.75-1.25	1.27	1.20-1.48	0.81	0.65-0.95
Lime, (CaO)	3.01	2.5-3.5	3.21	2.97-3.27	6.70	6.0-7.5
Magnesia, (MgO)	1.02	0.8-1.2	1.28	1.27-1.33	0.90	0.80-1.0
Sulfur Trioxide, (SO_3)	2.42	2.0-3.0	2.66	1.91-3.21	7.20	6.5-8.0
Potassium Oxide, (K_2O)	2.65	2.2-3.2	2.08	1.39-2.15	2.19	2.0-2.4
Sodium Oxide, (Na_2O)	0.50	0.4-0.7	0.14	0.12-0.45	0.58	0.50-0.70
Undetermined	0.24		2.78		0.40	
Fusion Temperature of Ash, F						
Reducing Atmosphere						
Initial Deformation	2,000	1,950-2,050	2,350	2,320-2,400	2,020	1,950-2,050
Softening (H-W)	2,150	2,100-2,200	2,510	2,500-2,600	2,130	2,050-2,200
Hemispherical (H-W/2)	2,200	2,150-2,250	2,670	2,600-2,740	2,160	2,100-2,200
Fluid	2,610	2,550-2,650	2,770	2,750-2,800	2,300	2,250-2,350
Viscosity T250, F	2,440	2,400-2,500	2,699	2,656-2,742	2,290	2,270-2,310
Oxidizing Atmosphere						
Initial Deformation	2,150	2,100-2,200			2,150	2,100-2,200
Softening (H-W)	2,290	2,250-2,350			2,320	2,280-2,360
Hemispherical (H-W/2)	2,350	2,300-2,400			2,350	2,300-2,400
Fluid	2,560	2,600-2,700			2,480	2,430-2,520
Viscosity, T250, F						
Fouling and Slagging Indices						
Base/Acid Ratio	0.37	0.34-0.40	0.206		0.52	0.48-0.56
Base/Acid Ratio x per cent Sulfur (dry basis)	1.13	1.05-1.21	0.167		2.16	2.0-2.3
Base/Acid Ratio x Na_2O (per cent of Ash)	0.19	0.17-0.21	0.029		0.30	0.25-0.35
Free Swelling Index	5.5	5.0-6.0	7	6-8	5.5	5.0-6.0
Hardgrove Grindability Index	55	50-60	73	65-75	55	53-58
Minimum Grindability Index	50		65		53	
Minimum Heating Value	12,200		12,900		10,900	
Top Size of Coal	1.5"		+1.25"		+2"	
Size of Bottom Mesh	28		28		28	
Per cent of Coal Passing Bottom Mesh	7.81	6-9	29.6	25-34	8.50	

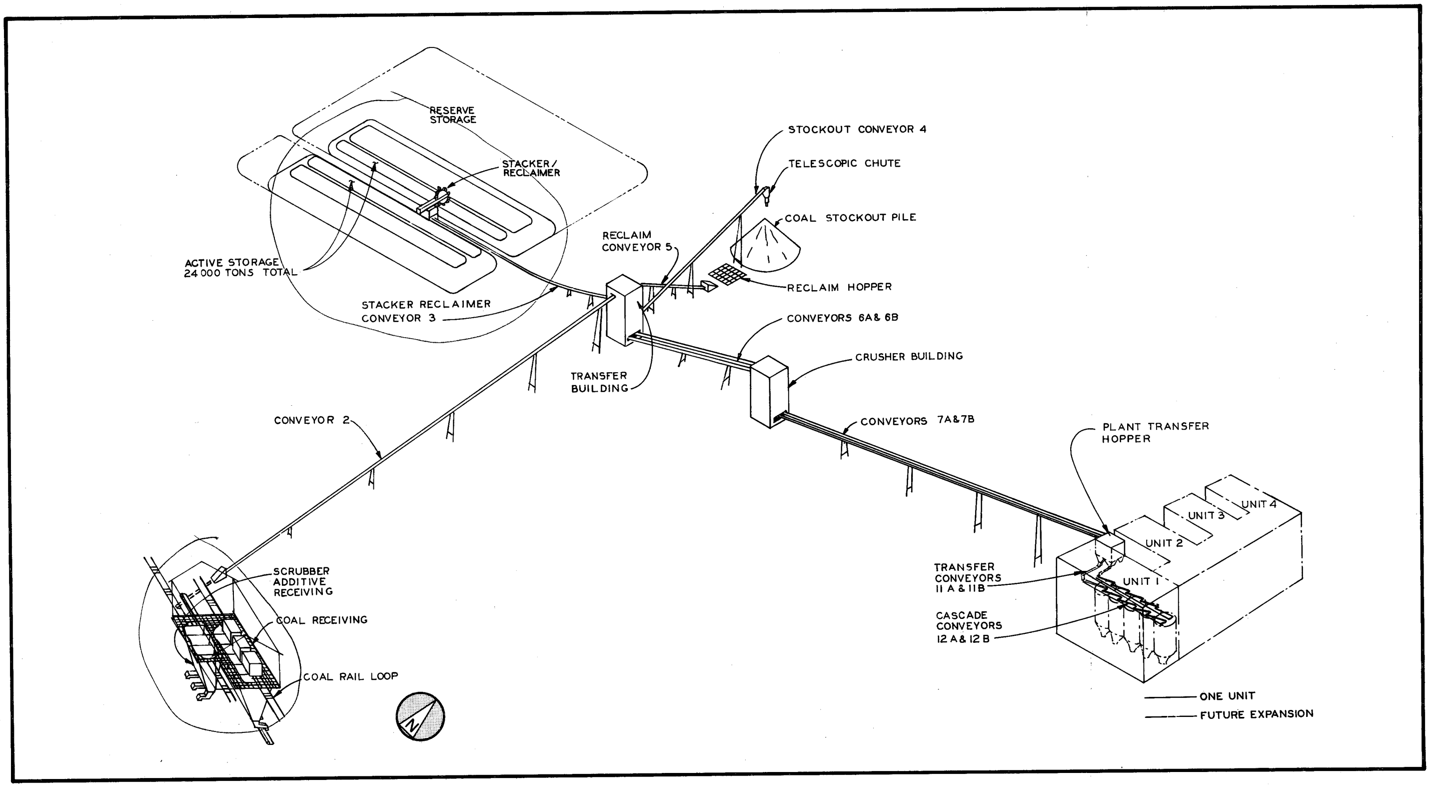

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Exhibit 6

FIGURE 3.2-3. PERSPECTIVE OF COAL HANDLING SYSTEM

TABLE 3.2-2. FUGITIVE COAL DUST EMISSIONS CONTROL

Source of Emissions	Dust Control Method	Control Efficiency per cent	
Bottom Car Dumper	Water Spray and Building Enclosure	97	5
Conveyor 2	Enclosed	90	RFM-1
Transfer Building	Enclosed and Baghouse	99+	
Conveyor 3	Wind Screen	50	
Active Storage			
Load In	Stacker Spray Water	75	
Load Out	Reclaimer Spray Water	80	
Wind Erosion	Water Spray and Compaction	80	
Conveyor 4	Enclosed	90	RFM-1
Emergency Stockout			
Load In	Telescopic Chute and Water	85	
Load Out	Dozer	50	
Wind Erosion	Limit Residence Time	80	
Emergency Reclaim	Bag Filter	99+	
Reserve Storage			
Load In	Dozer Sprayer Water	50	
Wind Erosion	Crusting and Chemical Sprays	90	
Conveyor 5	Enclosed	90	RFM-1
Conveyor 6A and 6B	Enclosed	90	
Crusher Building	Enclosed and Baghouse	99+	
Conveyor 7A and 7B	Totally Enclosed*	99	RFM-1a RFM-1
Surge Tower	Baghouse	99+	
Plant Silo	Baghouse	99+	

*With solid floor to protect other plant facilities and work areas. RFM-1a RFM-1

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TABLE 3.2-2. FUGITIVE COAL DUST EMISSIONS CONTROL

Source of Emissions	Dust Control Method	Control Efficiency per cent	
Bottom Car Dumper	Water Spray and Building Enclosure	97	5
Conveyor 2	Enclosed	90 99+	RFM-1
Transfer Building	Enclosed and Baghouse	99+	
Conveyor 3	Wind Screen	50	
Active Storage			
Load In	Stacker Spray Water	75	
Load Out	Reclaimer Spray Water	80	
Wind Erosion	Water Spray and Compaction	80	
Conveyor 4	Enclosed	90 99+	RFM-1
Emergency Stockout			
Load In	Telescopic Chute and Water	85	
Load Out	Dozer	50	
Wind Erosion	Limit Residence Time	80	
Emergency Reclaim	Bag Filter	99+	
Reserve Storage			
Load In	Dozer Sprayer Water	50	
Wind Erosion	Crusting and Chemical Sprays	90	
Conveyor 5	Enclosed	90 99+	RFM-1
Conveyor 6A and 6B	Enclosed	90 99+	
Crusher Building	Enclosed and Baghouse	99+	
Conveyor 7A and 7B	Enclosed	95* 99+	RFM-1
Surge Tower	Baghouse	99+	
Plant Silo	Baghouse	99+	

*One-half of Conveyor 7A and 7B gallery will be solidly floored; therefore, overall efficiency is 95 per cent. RFM-1

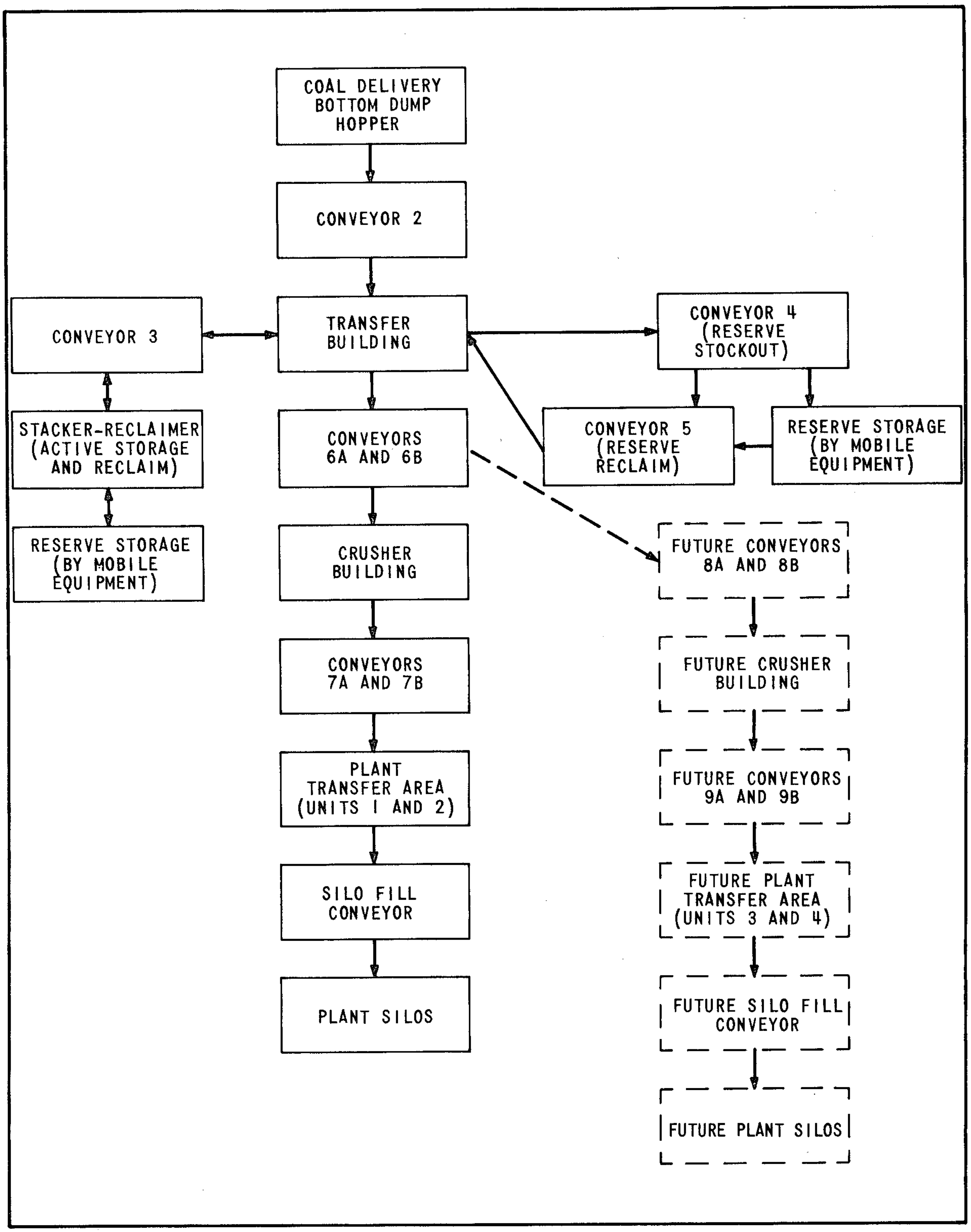

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FIGURE 3.2-1. COAL HANDLING SYSTEM

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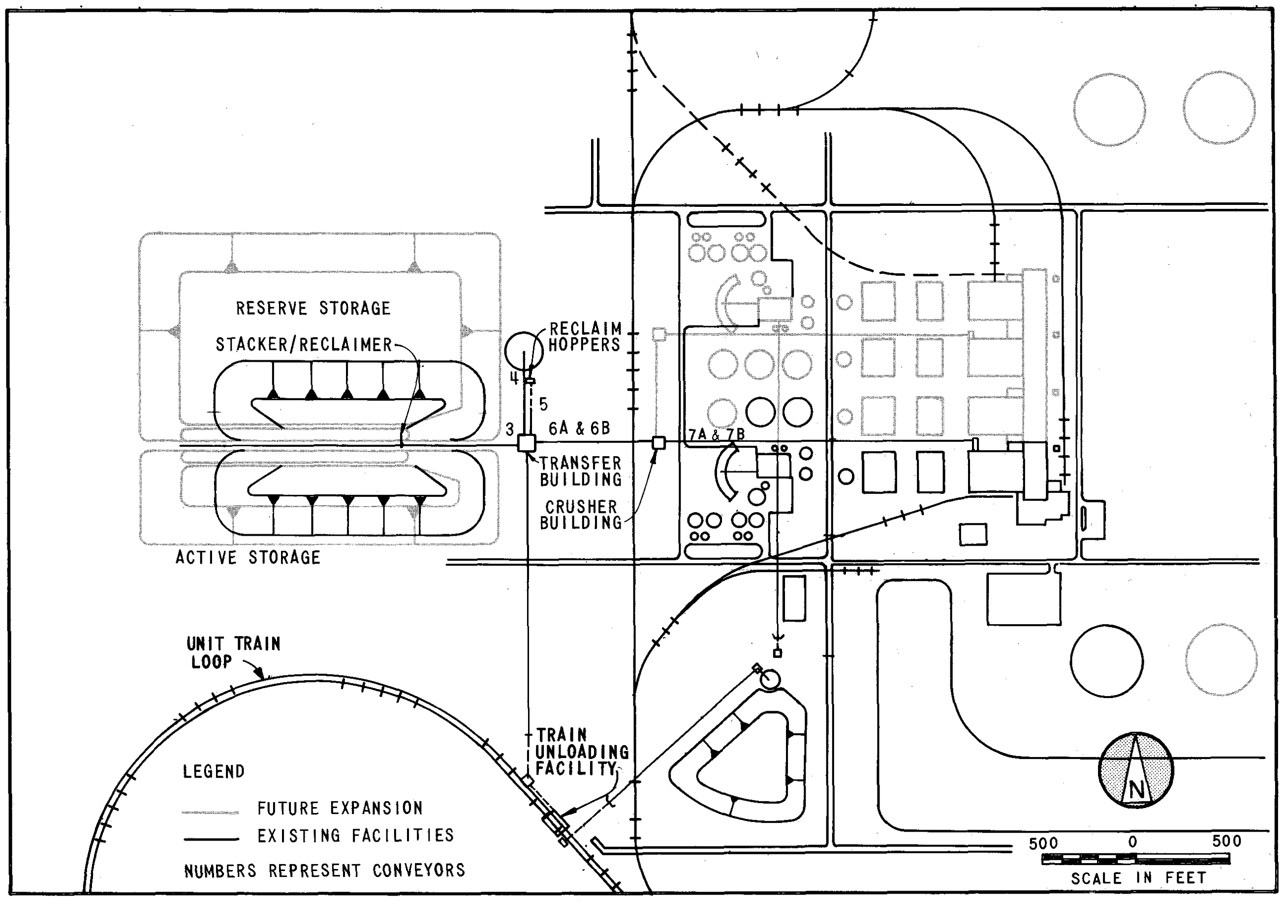

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FIGURE 3.2-2. COAL HANDLING SYSTEM LAYOUT

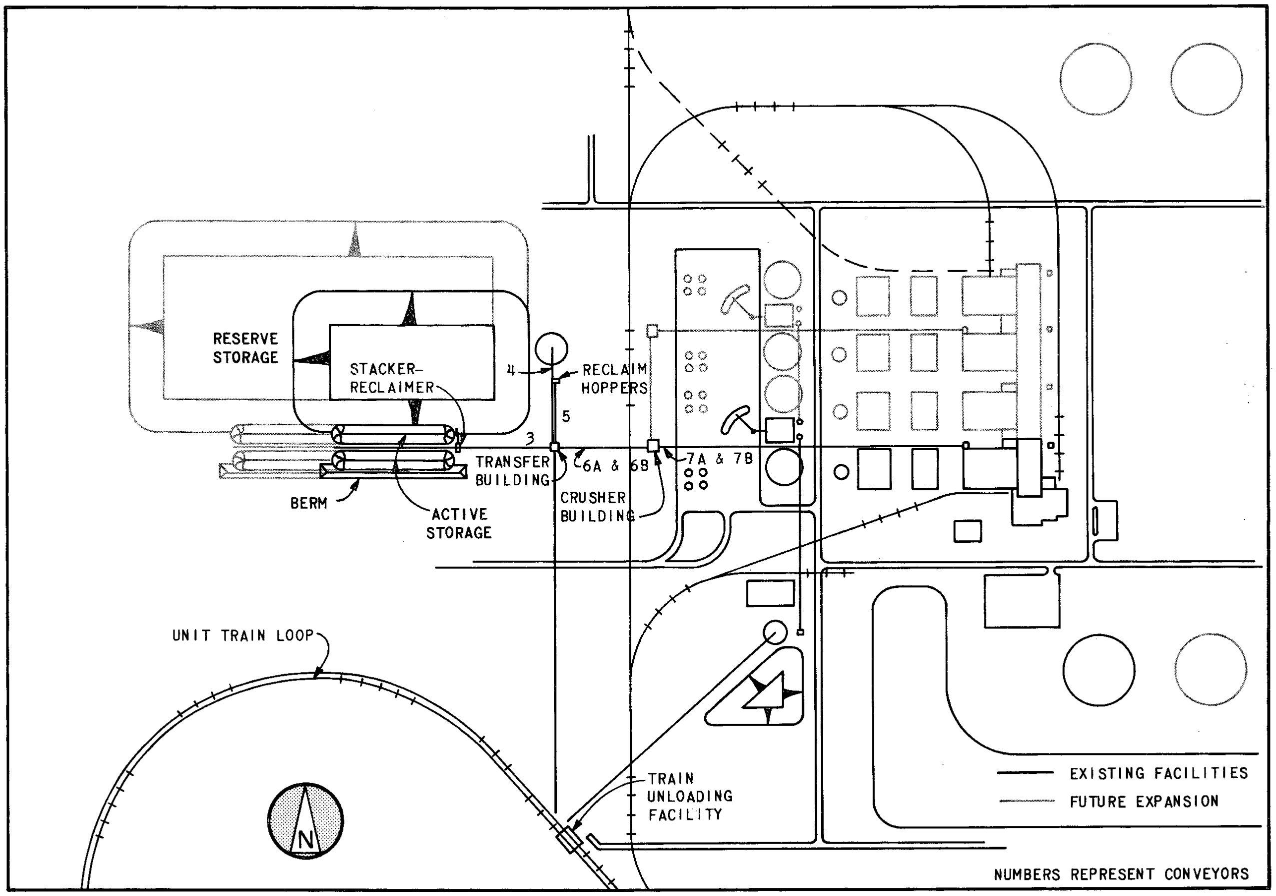

FIGURE 3.2-2. COAL HANDLING SYSTEM LAYOUT

3.3 PLANT WATER USE

Water used at the Stanton Energy Center will come from three sources: Orange County Easterly Subregional Wastewater Treatment Plant, wells, and RFM-1 precipitation. The majority of the water will be used as makeup to the cooling towers. Cooling tower makeup will be Orange County Plant effluent plus collected site runoff and direct precipitation on the makeup water supply storage pond. Well water will be used for potable water, general plant uses and steam cycle makeup. A water mass balance for normal and peak uses is shown on Figure 3.3-1. The water sources and water uses are described in the following subsections.

3.3.1 Water Sources

Cooling tower makeup will be primarily effluent from the Orange County Plant. The description of the source and quality is presented in Subsec- RFM-1 tion 3.4.2.

The well water will be from two 850 gpm onsite wells that will pump from the Floridan aquifer. For ultimate site development, a third well and pump will be installed along with the third unit. Only two of the three pumps will ever be operated at the same time. The well water will be 4 pumped directly to a solids contact unit for treatment by aeration, lime softening, filtration, and chlorination. The expected qualities of the raw and treated well water are shown on Table 3.3-1.

Precipitation from the central plant area will be collected and drained to the makeup water supply storage pond. This runoff and any direct precipitation on the makeup water supply storage pond will either evaporate, exfiltrate, or be used as cooling tower makeup. The precipitation runoff collected from the unlined coal storage area and the active solid waste disposal area will be directed to the lined recycle basin for use as scrubber and ash handling system makeup. The coal storage area runoff pond and the active solid waste disposal area runoff pond will also be lined. Site drainage is described in Section 3.10.

The precipitation collected in the ponds by direct precipitation and runoff are based on an annual average precipitation rate of 51.2 inches per year. Evaporation losses are based on an annual average evaporation of 47 inches per year.

3.3.2 Water Uses

3.3.2.1 Cooling Tower. The major use of water by the proposed project will be for makeup to the cooling tower. The rejection of waste heat from the steam cycle requires the evaporation of large amounts of water which must be replaced by makeup. To maintain the cooling tower water quality at nine cycles of concentration, blowdown is required to remove dissolved solids. Makeup is also required to replace the blowdown and drift losses that will occur. The makeup to the cooling tower will come from the makeup water supply storage pond. The water in the pond will come from the onsite sewage treatment plant effluent, Orange County Plant effluent, site runoff, RFM-1 and direct pond precipitation. Losses from the pond will consist of evaporation and seepage. On an annual average basis, seepage and evaporation will approximately equal site runoff and direct precipitation to the pond.

The cooling tower blowdown will be sent to the recycle basin for use as scrubber and ash handling system makeup or to a pump pit for return to the Orange County Plant. The amount of cooling tower blowdown returned to RFM-1 the Orange County Plant depends on the unit load, the amount of precipitation, and the type of coal burned. During periods of high precipitation and low loads, all cooling tower blowdown plus some miscellaneous plant drainage may be returned to the Orange County Plant since collected runoff RFM-1 and direct precipitation will be adequate to supply scrubber and ash handling system makeup. During periods of no precipitation and high unit loads, most of the cooling tower blowdown will be required for scrubber and ash handling system makeup. Another factor influencing cooling tower blowdown reuse is the type of coal used. Burning high sulfur coals would result in a greater use of blowdown than burning low sulfur coals. Burning of high sulfur coals would result in more scrubber sludge production and therefore more water would be lost in the disposal of the sludge (20-30 per cent water). The mass balance presented in Figure 3.3-1 is based on a low sulfur coal (the precipitator design coal shown in Section 3.2) and therefore represents a mass balance with a high annual average return of cooling tower blowdown to the Orange County Plant. The quality of the cooling RFM-1 tower blowdown to be returned to the Orange County Plant is described in Subsection 3.4.3. RFM-1

3.3.2.2 Recycle Basin. The recycle basin shown on Figure 3.3-1 will be a lined pond designed to collect plant wastewater for use as scrubber and ash handling system makeup. Inflows to the basin include direct precipitation, coal storage area runoff, active solid waste disposal area runoff, cooling tower blowdown, neutralization basin effluent, and miscellaneous plant drains.

3.3.2.3 Bottom Ash and Pulverizer Rejects. The ash handling system will utilize water for sluicing the bottom ash and pulverizer rejects from the bottom ash hoppers and pulverizer rejects hoppers. The ash will be dewatered prior to being transported to the solid waste disposal area, with the sluice water being reclaimed and reused in the ash handling system. Water from an ash water storage tank will be used to sluice bottom ash and pulverizer rejects from the bottom ash hoppers and pulverizer rejects hoppers to a transfer tank. From the transfer tank, the slurry will be pumped to a batch-type dewatering bin for gravity decanting of the sluice water and temporary storage of the ash material. The dewatered bottom ash and pulverizer rejects will be taken from the dewatering bins and transported to the solid waste disposal area. Decant from the dewatering bins will overflow into an ash water settling tank for further clarification. Clarified water from the settling tank will be stored in the ash water storage tank while the sludge will be pumped back to the dewatering bins.

Makeup to the dewatering system will be required to replace the water entrained in the ash discharged from the bins, and also for evaporation losses. Makeup water other than the service water added as seal and flush water, will be supplied to the ash water storage tank from the recycle basin. The amount of makeup will depend on the unit load, the type of coal that is being burned, the supply requirements as established by the ash handling system manufacturer, and the time duration for a given conveying cycle. A small amount of service water will be required for crusher seal water and ash sluice gate flush water.

3.3.2.4 Flue Gas Scrubber. A wet limestone type scrubber will be used for
the removal of sulfur dioxide from the flue gas. Limestone will be fed as
a slurry to a scrubber module where it comes in contact with the flue gas
and reacts with sulfur dioxide to form a calcium sulfate/sulfite precipitate.
The spray slurry drains into the reaction tank and is recirculated back to
the scrubber module. A portion of the spray slurry is bled off from the
reaction tank to the thickener. Clarified thickener overflow water is
returned to the reaction tank. The sludge, which contains primarily cal-
cium sulfate and calcium sulfite with some unreacted limestone, is de- 5
watered and transferred to a mixer where it is blended with boiler hopper
and fly ash that has been collected in the boiler hopper and removed from
the flue gas by electrostatic precipitators. Scrubber sludge combined with
fly ash and boiler hopper ash will form a stable mixture which will be
transported to the solid waste disposal area. Makeup water from the re-
cycle basin will be required by the desulfurization system to replace water
entrained in the solids and evaporation losses. The amount of makeup
required will depend on the type of coal that is being burned and the unit
load. All water entering the scrubber system will eventually be either
evaporated or entrained in the solid waste. Service water will be required
by the desulfurization system for seal water and various other uses.

3.3.2.5 Combustion Waste Storage. Ash and scrubber solids will be stored
in 15-acre active areas. Runoff from the active areas will be collected in
the lined, active combustion waste area runoff pond. The runoff pond will
be sized to contain runoff and direct precipitation from a 100-year, 24-hour
rainfall event, assuming an active area of 15 acres. Controlled drainage 5
of the active combustion waste area runoff pond to the recycle basin will
be accomplished through a buried pipeline.

Runoff from the nonactive areas will be directed to the site natural
drainage systems in the area. Nonactive areas are undeveloped portions 5
(areas not yet utilized for combustion waste storage) and developed portions

(former active segments which have been reclaimed by covering with topsoil 5
and revegetated).

3.3.2.6 Coal Storage Area. A lined pond will be provided to collect rainfall runoff from the unlined coal pile and surrounding coal yard area. The pond will be sized to contain runoff and direct precipitation from a 10-year, 24-hour rainfall event. Runoff from precipitation exceeding the
10-year, 24-hour event will be directed to the recycle basin. Controlled 5
drainage of the coal storage area runoff pond to the recycle basin will be accomplished through a buried pipeline.

3.3.2.7 Service Water. A solids contact type softener-clarifier and a gravity filter system will be provided for the treatment of the well water. Lime, coagulant, and coagulant aid will be fed to the solids contact basin for softening the raw water. The solids contact basin will have a concentrator section for collecting the sludge produced in the softening reaction. The sludge will be withdrawn at the rate it is produced and will be piped to a sump. Gravity filters will be provided for filtering the solids contact basin effluent. The filter backwash wastewater will also be piped to the sludge sump. From the sludge sump, the service water treatment wastes will be routed to the flue gas desulfurization system. The service water (gravity filter effluent) will be stored in two 500,000 gallon service water storage tanks. Half of this volume will be dedicated to fire protection. The service water will be of potable quality and, therefore, potable water supply will be from the service water system.

3.3.2.8 Sanitary Wastes. Treatment of the sanitary wastes is described in Section 3.6. Effluent from the onsite sanitary treatment plant will be directed to the makeup water supply storage pond for use as cooling tower makeup.

3.3.2.9 Chemical Wastewater. As described in Section 3.5, various plant chemical wastewaters are collected and then neutralized in a neutralization basin. From the neutralization basin, the wastewater will be transported to the recycle basin. Essentially, all chemical wastewater will be regenerant wastes from the makeup demineralizer and condensate polishers.

3.3.2.10 Miscellaneous Plant Drains. Miscellaneous plant drains will collect wastewater from recovered steam cycle losses and miscellaneous plant services, such as normal plant cleaning, maintenance activities, equipment and pipe leakage, and relief valve drains. Steam cycle losses will result from evaporation, blowdown, soot blowing, and leakage. Miscellaneous plant drains will be routed to the recycle basin for use in other plant systems or will be routed to the pump pit for return to the Orange County Plant with the cooling tower blowdown. RFM-1

3.3.3 Water Consumption

Table 3.3-2 presents the annual average water consumption for Unit 1. Also presented is water flow before plant construction begins. The flow rates for precipitation and evaporation are based on the area of site to be developed (area in which precipitation is collected).

Water consumption during unit shutdown will consist of well water which will be treated and supplied to the service water system. From the service water system, water will be supplied for potable uses, demineralization, and miscellaneous plant services. The potable flow will be approximately the same as during unit operation. The other two flows will be greatly reduced from normal operation amounts.

Water for construction will be provided by one of the onsite wells. Water from the well will be treated by a temporary construction chlorination facility and aerator before storage in a service water tank. Estimated construction water consumption is 300 gpm.

TABLE 3.3-1. ANTICIPATED RAW WELL WATER AND TREATED WATER ANALYSES

Constituent	Raw Well Water			Treated
	Minimum	Maximum	Typical	Typical*
Calcium as $CaCO_3$	114	302	280	37
Magnesium as $CaCO_3$	14	41	18	16
Sodium as $CaCO_3$	17	35	30	30
Potassium as $CaCO_3$	1	2	1	1
M-Alkalinity as $CaCO_3$	170	289	288	35
Sulfate as $CaCO_3$	1	15	13	21
Chloride as $CaCO_3$	10	28	28	28
Silica as SiO_2	8	25	14	14
Iron as Fe	0.05	2	1.2	0

*Assumes 1 grain per gallon alum added as coagulant.

TABLE 3.3-2. AVERAGE ANNUAL WATER BALANCE*

	Balance During Average Unit Operation gpm	Balance Before Construction gpm		
Water Inflows				
Precipitation	1,019	1,019	5	
Orange County Plant Effluent	2,644	0	5	RFM-1
Well Water	202	0		
Total	3,865	1,019	5	
Water Losses				
Evaporation and Transpiration	3,322	779	5	
Runoff to Natural Drainage	0	200	5	
Seepage	280	40	5	RFM-1
Return to Orange County Plant	251	0	5	RFM-1
Wastewater Disposal Retention	12	0		
Total	3,865	1,019	5	

*Based on area of site where precipitation runoff is collected. 4

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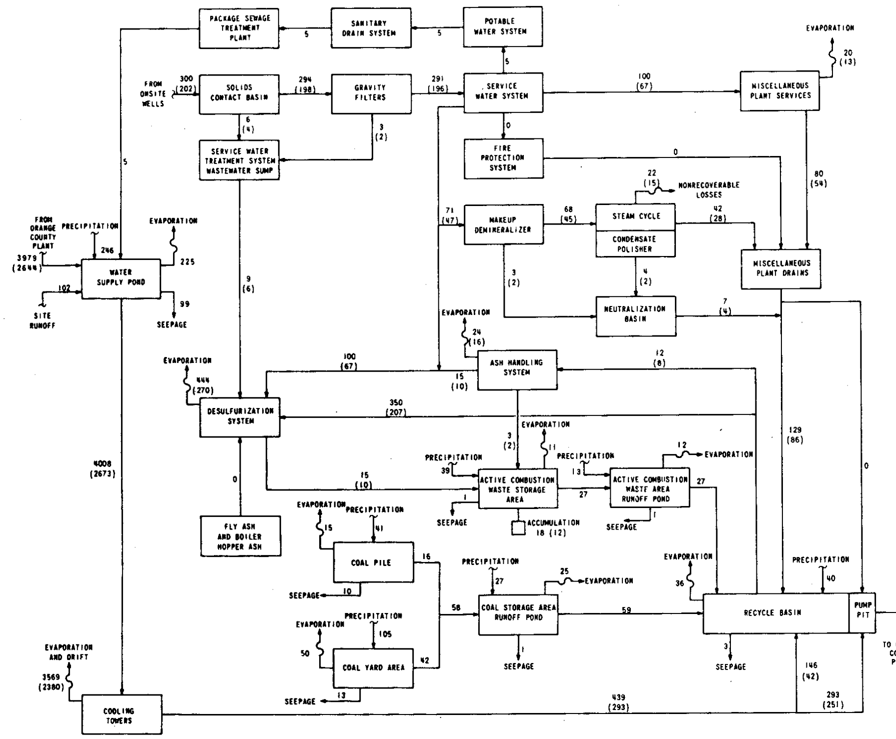

NOTES:

1. ALL FLOWS ARE EXPRESSED IN GALLONS PER MINUTE.
2. FLOWS NOT IN PARENTHESES REPRESENT TYPICAL REQUIREMENTS FOR ONE UNIT OPERATING AT 100 PER CENT LOAD.
3. FLOWS IN PARENTHESES REPRESENT REQUIREMENTS FOR ONE UNIT OPERATING AT AVERAGE. LOAD OF 66.7 PER CENT WHILE OPERATING WHEN DIFFERENT FROM THE REQUIREMENT AT 100 PER CENT LOAD.
4. MASS BALANCE IS BASED ON BURNING LOW SULFUR APPALACHIAN COAL.

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FIGURE 3.3-1. WATER MASS BALANCE FOR UNIT 1

3.4 HEAT DISSIPATION SYSTEM

Plant waste heat will be rejected to the atmosphere in a closed-cycle circulating water system utilizing a natural draft cooling tower. Makeup water to the closed-cycle cooling system will be treated effluent from the Orange County Easterly Subregional Wastewater Treatment Plant. RFM-1

3.4.1 Intake and Outfall

An intake will be located at the Orange County Plant to pump treated effluent to an on-site storage pond. Another intake will be located in the on-site makeup water supply storage pond to pump makeup water from the pond to the cooling tower. An outfall will be located in a basin adjacent to the recycle basin. The outfall will contain pumps to pump cooling tower blowdown in excess of that required for makeup to the recycle basin or to the Orange County Plant. None of these structures will be located in existing bodies of water.

3.4.2 Source of Cooling Water

The water for use in the heat dissipation system will come from the Orange County Easterly Subregional Wastewater Treatment Plant. The Orange County Plant is located 7 miles east of the City of Orlando in Section 3, RFM-1
R31E, T23S. The facility is designed for secondary and advanced wastewater treatment. Secondary treatment includes removal of suspended solids and biochemical oxygen demand. Advanced wastewater treatment includes phosphorus removal, nitrogen removal, filtration, and chlorination. Makeup water for the Stanton Energy Center cooling towers will be final plant effluent. The expected effluent quality is shown in Table 3.4-1. RFM-1

The effluent will be pumped to the Stanton Energy Center site in a buried 36-inch fiberglass reinforced plastic pipe. The routing of the pipe is described in Subsection 3.9.5. The pipe is sized to supply the makeup water requirement of the ultimate four unit development.

The estimated maximum makeup rate for the Unit 1 cooling system is
4,008 gpm. At a lifetime capacity factor of 53.6 per cent (66.7 per cent 5
load while operating), the average makeup rate is expected to be 2,673 gpm.
The flow rate of the Orange County Plant effluent is predicted to average
6 million gallons per day. Storage ponds at the Orange County Plant will
provide adequate surge capacity for sewage treatment plant effluent to 5 RFM-1
allow pumping of the effluent on an as-needed basis.

The onsite makeup water supply storage pond arrangement is shown on
Figure 3.1-4. The pond will have a surface area of 93 acres and an embank- 4
ment length of about 10,000 feet. The bottom of the pond will be excavated
to an average elevation of 62 feet, msl. Excavated material will be used 5
as embankment and/or general site fill. A detailed description of the
makeup water supply storage pond is contained in Section 3.10.

The pond will be used for site runoff collection as well as for makeup
water storage. Pond size is established by runoff collection requirements
during Unit 1 construction as well as the estimated maximum makeup water
requirement for one week with four units operating (560 acre-feet). The 5
estimated average pond seepage rate is 99 gpm and estimated average annual
evaporation rate is 226 gpm. The estimated average annual direct precipi- 4
tation equates to a makeup rate to the pond of 246 gpm. The average annual
site runoff to the pond equates to a makeup rate of 102 gpm. Thus, the
average yearly losses from seepage and evaporation (325 gpm) will approxi- 5
mately equal the average yearly makeup from direct rainfall and site runoff
(348 gpm). 5

In addition to the water sources described above, the effluent from
the Stanton Energy Center sanitary wastewater treatment plant will also be

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The estimated maximum makeup rate for the Unit 1 cooling system is
4,008 gpm. At a lifetime capacity factor of 53.6 per cent (66.7 per cent 5
load while operating), the average makeup rate is expected to be 2,673 gpm.
The flow rate of the Iron Bridge Facility effluent is predicted to vary
from 4,000 to 46,000 gpm. At the lowest flow the discharge rate may be
nearly equal to the Unit 1 maximum demand and considerably less than the 5
maximum demand for the ultimate four unit development. Therefore, the
effluent for makeup supply will be pumped to an on-site storage pond during
high discharge rate periods and the pumping system will be shut down during
low discharge rate periods. The initial pumping installation at the Iron
Bridge Facility will include three vertical wet pit pumps in a surge type
storage basin. Two pumps will be capable of supplying the water requirements
of the first two units at the site. The third pump will be a standby pump.
The ultimate four unit development will require the addition of two more
pumps to the pump structure.

The onsite makeup water supply storage pond arrangement is shown on
Figure 3.1-4. The pond will have a surface area of 93 acres and an embankment 4
length of about 10,000 feet. The bottom of the pond will be excavated to 5
an average elevation of 62 feet, msl. Excavated material will be used as
embankment and/or general site fill. A detailed description of the makeup
water supply storage pond is contained in Section 3.10.

The pond will be used for site runoff collection as well as for makeup
water storage. Pond size is established by runoff collection requirements
during Unit 1 construction as well as the estimated maximum makeup water
requirement for one week with four units operating (560 acre-feet). The 5
estimated average pond seepage rate is 99 gpm and estimated average annual
evaporation rate is 226 gpm. The estimated average annual direct precipi- 4
tation equates to a makeup rate to the pond of 246 gpm. The average annual
site runoff to the pond equates to a makeup rate of 102 gpm. Thus, the
average yearly losses from seepage and evaporation (325 gpm) will approxi- 5
mately equal the average yearly makeup from direct rainfall and site runoff
(348 gpm). 5

In addition to the water sources described above, the effluent from
the Stanton Energy Center sanitary wastewater treatment plant will also be

discharged into the makeup water supply pond and used as cooling tower makeup. The estimated annual average effluent rate is 5 gpm.

Makeup to the cooling towers will be pumped to the tower from the makeup water supply storage pond by two full capacity pumps located in a pump structure in the pond.

3.4.3 System Design

The system consists of a condenser, a natural draft cooling tower, circulating water pumps, and supply and return circulating water piping.

The surface condenser will be a single-pressure, single-shell, surface condenser located in the generator building directly beneath the steam turbine low pressure exhaust. The condenser will be designed to operate under maximum conditions with the following parameters.

(1) Condenser surface area--270,000 square feet.

(2) Circulating water flow--175,000 gpm, 1st pass/200,000 gpm, 2nd pass. 5

(3) Tube material--Type 304 stainless steel.

(4) Tube sheet material--Carbon steel.

(5) Peak pressure--3.35 inches HgA. 5

(6) Circulating water inlet temperature--91.7 F.

(7) Maximum heat rejection--2.02 x 10^9 Btu/h. 5

In addition to the surface condenser, an auxiliary cooling system for equipment cooling will be located in the generation building. This system consists of two water-to-water heat exchangers, and receives cooling water from the circulating water system at the rate of approximately 25,000 gpm. The cooling water in this system is subsequently returned to the second pass of the condenser. 5

The cooling tower will be a natural draft, counterflow, cooling tower with an approximate base diameter of 290 feet and an approximate height of 430 feet. The tower will be constructed of concrete and will utilize polyvinyl chloride fill. The cooling tower will be designed to operate under the following conditions. 5

(1) Circulating water flow--200,000 gpm.

(2) Tower approach--13 F.

(3) Tower range--22.8 F.

(4) Design wet bulb temperature--78 F.

(5) Design relative humidity--55 per cent.

(6) Maximum heat rejection--2.28 x 10^9 Btu/h.

The circulating water will be pumped from the cooling tower to the condenser and back to the cooling tower by circulating water pumps through buried concrete circulating water lines.

The cooling tower maximum evaporation rate will be approximately 3,559 gpm. The predicted makeup water quality should allow the cooling tower to operate at nine cycles of concentration. Based on the nine cycles of concentration, maximum blowdown will be approximately 439 gpm. The quality of the circulating water is shown in Table 3.4-2. Blowdown will be from the cold side of the cooling tower with a maximum expected temperature RFM-1 of approximately 98 F. Cooling tower blowdown will be used as makeup to the recycle basin with excess blowdown pumped to the Orange County Plant through a pipeline approximately 4 miles in length. The temperature of the blowdown at the Orange County Plant will be the same temperature as the ground in which the pipeline is buried. Estimated travel time in the pipeline when the return pumps are operating is approximately 1.5 hours.

The circulating water will be treated with chemicals to protect the system and to prevent excessive scaling and corrosion. Sulfuric acid will be added at the cooling tower basin to reduce alkalinity and to control the scaling tendency of the circulating water system. Control of sulfuric acid feed will be in proportion to the makeup water flow with a pH bias. To further inhibit scale deposition, organic phosphates will be automatically fed at the cooling tower basin as a sequestering agent. To prevent biofouling of the circulating water system, intermittent shock chlorination will be used. A chlorine solution will be fed into the circulating pump basin through diffusers.

TABLE 3.4-1. ESTIMATED MAKEUP WATER ANALYSIS FROM ORANGE COUNTY EASTERLY SUBREGIONAL WASTEWATER TREATMENT PLANT RFM-1

Chemical Constituents	Effluent Concentration
Calcium, mg/l as $CaCO_3$	88
Magnesium, mg/l as $CaCO_3$	33
Sodium, mg/l as $CaCO_3$	108
Alkalinity, mg/l as $CaCO_3$	89
Sulfate, mg/l as $CaCO_3$	16
Chloride, mg/l as $CaCO_3$	120
Silica, mg/l as SiO_2	15
Iron, mg/l as Fe	0.5
Residual Chlorine, mg/l as Cl	1
Treated Water Characteristic	
Suspended Solids, mg/l	5
Biochemical Oxygen Demand, mg/l	5
Total Nitrogen, mg/l as N	3
Total Phosphorus, mg/l as P	1

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TABLE 3.4-2. ESTIMATED CIRCULATING WATER ANALYSIS

Chemical Constituents*	Concentration		
Calcium, mg/l as $CaCO_3$	792		RFM-1
Magnesium, mg/l as $CaCO_3$	297		
Sodium, mg/l as $CaCO_3$	972	5	
Alkalinity, mg/l as $CaCO_3$	200		
Sulfate, mg/l as $CaCO_3$	745		
Chloride, mg/l as $CaCO_3$	1,080	5	
Nitrate, mg/l as $CaCO_3$	36	5	
Silica, mg/l as SiO_2	135		
Iron, mg/l as Fe	4.5	5	
Total Nitrogen, mg/l as N	27		
Total Phosphorus, mg/l as P	20		
pH	8.0-8.5		

*Based on operating at nine cycles of concentration, feeding H_2SO_4 to control alkalinity to 200 mg/l as $CaCO_3$, and utilizing an organic phosphate scale inhibitor.

3.5 CHEMICAL AND BIOCIDE WASTES

The principal uses of chemicals and biocides at the proposed project will be for cooling tower circulating water quality control, steam cycle water quality control, service water treatment, sanitary wastewater treatment, makeup water demineralization, steam cycle condensate polishing, chemical cleaning of the boiler and preboiler cycle piping systems, and miscellaneous chemical drains.

3.5.1 Cooling Tower Circulating Water Treatment

The cooling tower circulating water systems will use sulfuric acid for pH control, chlorine injection for control of algae and biofouling, and an organic phosphate as a scale inhibitor. The sulfuric acid and organic phosphate will be stored in tanks located in a curbed area beside the circulating water pump structures. The chlorine will be stored in 2000-pound containers in the same area. The estimated average usage of these chemicals based on the quality of the Orange County Plant effluent listed in Table 3.4-1 will be 148 gallons per day of 66 degree Baumé sulfuric acid, 10 gallons per day of the organic phosphate, and 200 pounds per day of chlorine. The chemicals will be discharged in the cooling tower blowdown. Part of the cooling tower blowdown will be used as scrubber and ash handling system makeup with the remainder to be returned to the Orange County Plant as described in Subsection 3.3.2.

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3.5.2 Steam Cycle Water Treatment

The steam cycle water will be treated using hydrazine for oxygen scavenging and ammonia for pH control. Sodium phosphate may be fed to the cycle water in the event of a condenser tube leak. Residual phosphate will react with calcium hardness to form a non-adherent precipitate. The hydrazine and sodium phosphate will be stored in the Generation Building and the ammonia will be stored outside the Generation Building. Estimated average usages of these chemicals are 2 pounds per day of hydrazine and 51 pounds per day of ammonia. Sodium phosphate will not normally be used. If the condensate polishing system is operated past ammonia breakthrough, ammonia usage can be reduced to approximately 1 pound per day. Boiler blowdown will be routed to the recycle basin.

3.5.3 Service Water Treatment

The service water treatment system will soften and remove iron from the plant well water supply. Chemicals used will be lime, coagulant, a coagulant aid, and chlorine. Hydrated lime will be stored in a hopper and will be mixed with service water to form a slurry before addition to the solids contact basin. The coagulant and coagulant aid will be stored in tanks in the Water Management Building and pumped to the solids contact basin as required. A gas solution chlorination system will feed chlorine solution into the gravity filters effluent to assure dissinfection and a potable service water system. Chlorine will be stored in 150 pound cylinders in an isolated room in the Water Management Building. Estimated average usages of these chemicals are 597 pounds per day of lime (90 per cent CaO), 41 pounds per day of coagulant (aluminum sulfate), 1.2 pounds per day of coagulant aid (Calgon 243), and 5 pounds per day of chlorine.

The solids contact basin will have a concentrator section for collecting the sludge produced in the softening reaction. The sludge will be withdrawn at the rate it is produced and will be piped to a sump. Gravity filters will be provided for filtering the solids contact basin effluent. The filter backwash wastewater will also be piped to the sludge sump. From the sludge sump, the water treatment wastes will be routed to the flue gas desulfurization system.

The chemical feed and the resultant amount of precipitated sludge produced in the solids contact basin will depend upon the flow throughput and the raw water chemical characteristics. Based on the well water analysis presented on Table 3.3-1, 5.4 pounds of precipitate, predominantly calcium carbonate, will be formed per 1,000 gallons throughput. Assuming a 3 per cent solids concentration in the sludge, the average waste water flow will be approximately 6,100 gpd. It is anticipated that two gravity filter modules with three bays per module will be provided. When required, each bay will be backwashed for 15 minutes at a rate of 12 gpm per square foot of filter area. The average estimated backwash flow is 2,470 gpd.

3.5.4 Sanitary Wastewater Treatment

The sanitary treatment system will use chlorine tablets (sodium hypochlorite) or a gas solution chlorination system for bacteria control in the effluent. The sanitary treatment process is described in Subsection 3.6.2.

3.5.5 Makeup Water Demineralization

The demineralizer system will use sodium hydroxide for anion resin regeneration and sulfuric acid for cation resin regeneration. The sodium hydroxide and sulfuric acid will be stored in tanks located in or adjacent to the Water Management Building. The uses of these chemicals will be on an intermittent basis dependent on demineralizer operation. Based on the annual plant capacity factor and makeup requirements, the estimated usage rate for 66 degree Baumé sulfuric acid will be 121 pounds per day and the rate of 100 per cent sodium hydroxide will be 70 pounds per day. The wastes from this system will be regenerant waters containing unreacted sulfuric acid and caustic plus sodium and sulfate salts of the ions removed from the ion exchange resins during regeneration. The estimated regenerant wastes will average 3,270 gpd. These wastes will be routed to the neutralization basin for neutralization as described in Subsection 3.5.9.

3.5.6 Steam Cycle Condensate Polishing

The condensate polishing system will also use sodium hydroxide for anion resin regeneration and sulfuric acid for cation resin regeneration. The sodium hydroxide will be stored in a tank in the Generation Building and the sulfuric acid will be stored in a curbed area adjacent to the Generation Building. The use of these chemicals will be on an intermittent basis and dependent on polisher operation. Based upon the annual plant capacity factor, full flow condensate polishing and operation past the ammonia breakthrough point; the estimated usage rate of 66 degree Baumé sulfuric acid will be 72 pounds per day and the rate for 100 per cent sodium hydroxide will be 41 pounds per day. The wastes from this system will be regenerant waters containing unreacted sulfuric acid and caustic plus sodium and sulfate salts of the ions removed from the ion exchange resins during regeneration. The estimated wastes will average 3,800 gpd. These wastes will be routed to the neutralization basin for neutralization as described in Subsection 3.5.9.

3.5.7 Chemical Cleaning

The steam generator and pre-boiler cycle piping will be chemically cleaned initially during commissioning and also periodically during the life of the plant. The chemicals used will not be stored onsite and will be administered utilizing a temporary system. The chemical cleaning solutions to be used for acid and alkaline cleaning of the boiler will be somewhat dependent on the boiler manufacturer selected. The actual cleaning solutions used must be consistent with the boiler manufacturer's recommendations. Chemicals used in boiler and preboiler cleaning include the following.

(1) Inhibited hydrochloric acid.
(2) Ammonia bifluoride.
(3) Hydroxyacetic acid.
(4) Formic acid.
(5) Disodium phosphate.
(6) Trisodium phosphate.
(7) Soda ash.
(8) Non-foaming wetting agents.
(9) Foam inhibitors.

These wastewaters will consist of the cleaning solutions and material removed during the cleaning process. Since chemical cleaning is a maintenance operation, it does not contribute to the liquid wastes produced by the normal operation of the plant. The preoperational chemical cleaning wastes are estimated to be approximately 650,000 gallons, with subsequent acid cleaning of the boiler alone resulting in an estimated additional 330,000 gallons for each cleaning operation. This waste will be routed to the neutralization basin for neutralization as described in Section 3.5.9.

3.5.8 Miscellaneous Chemical Drains

Chemical wastewaters can result from draining a chemical storage tank, overflowing a chemical tank during a filling operation, or from maintenance operations such as hosing down chemical storage areas. A separate floor drain collection system will be provided to route miscellaneous chemical wastes to the neutralization basin. Flows from the miscellaneous chemical drains will be intermittent and will not normally contribute to the wastewater flows.

3.5.9 Neutralization Basin

A neutralization basin of approximately 120,000 gallons capacity will be provided for treatment of chemical wastes prior to their ultimate disposal. A basin of this capacity will be sufficient to simultaneously accommodate the wastewaters produced during regeneration of the makeup demineralizer and one condensate polisher, and will handle the largest volume of chemical cleaning solution wastes expected at one time, that being the acid cleaning solution from a steam generator. The neutralization basin will be a reinforced concrete basin lined with chemical resistant membrane, brick, and mortar. A chemical waste mixer, mounted on a walkway spanning the basin, will be provided to hasten neutralization of the chemical wastes. Sulfuric acid and sodium hydroxide, as required for neutralization, will be available from the makeup demineralizer regeneration equipment. The neutralized chemical wastewaters will be transported to the recycle basin.

3.6 SANITARY AND SOLID WASTES

3.6.1 Sanitary Wastes

The construction sanitary wastes will be disposed of by two methods. The construction office building and the construction change buildings will have sanitary facilities which will discharge into the plant sanitary waste treatment facility located beside the makeup water supply storage pond. Other construction sanitary wastes will be collected locally throughout the plant in portable toilet facilities and will be removed by the site services contractor. The plant sanitary waste treatment facilities will consist of a package sewage treatment plant. The package sewage treatment plant will be an activated sludge unit which employs the extended aeration process method of treatment. The process equipment will be installed in a concrete basin with separate aeration and clarification sections. A comminutor will be provided to reduce the size of solids at the inlet to the plant. A chlorine contact chamber and a gas solution chlorination system will be provided to disinfect the effluent. Treated effluent from the packaged plant will be discharged to the makeup water supply storage pond for percolation.

During Unit 1 operation, sanitary waste from each of the permanent buildings having sanitary facilities will gravity flow in a piping system to the plant sanitary sewage treatment facilities located beside the makeup water supply storage pond. The effluent from the facilities will be discharged to the makeup water supply storage pond for use as cooling tower makeup.

Prior to operation of Unit 1, the estimated hydraulic loadings for the sewage treatment plant will be as follows.

400 construction personnel at 20 gpd	8,000 gpd
75 construction supervisory and secretarial personnel at 25 gpd	1,875 gpd
50 visitors and temporary personnel at 25 gpd	1,250 gpd
TOTAL	11,125 gpd

Biological loading will be approximately 0.045 pound of BOD_5 per day for construction personnel, visitors, and temporary personnel, or a total of approximately 24 pounds of BOD_5 per day.

After construction is complete and Unit 1 is operating, the estimated hydraulic loading figures are as follows.

163 permanent personnel at 35 gpd	5,700 gpd
20 visitors and temporary personnel at 25 gpd	500 gpd
TOTAL	6,200 gpd

Biological loading will be approximately 0.075 pound per day of BOD_5 for permanent personnel and 0.045 pound per day of BOD_5 for visitors and temporary personnel or a total of approximately 13 pounds per day of BOD_5.

3.6.2 Solid Wastes

The solid wastes generated by the operation of Stanton Energy Center, Unit 1 will consist of fly ash, boiler hopper ash, flue gas desulfurization wastes, bottom ash and coal pulverizer rejects. These wastes will be stored onsite in an unlined landfill (combustion waste storage) area on the west side of the site. The quantities of waste produced will depend on the coal burned. The following quantities are based on a typical washed Illinois coal.

The fly ash will be collected by an electrostatic precipitator. The
estimated production of fly ash is 46,000 tons/yr. The fly ash will be 5
conveyed by vacuum to a fly ash storage silo. A bag filter will be employed to control fugitive emissions from the silo and vacuum system.

The fly ash which falls out in the boiler hopper will be conveyed to the fly ash storage silo by a branch of the fly ash vacuum transport system.
Estimated production of boiler hopper ash is 2,400 tons/yr. 5

The scrubber sludge produced in the flue gas desulfurization (FGD) equipment is estimated at 201,000 tons/yr. The sludge from the FGD system will contain primarily calcium sulfate and calcium sulfite, with inerts and
some unreacted limestone. The scrubber sludge will be dewatered by thick- 5
eners and vacuum filters to approximately 50 to 60 per

Biological loading will be approximately 0.045 pound of BOD_5 per day for construction personnel, visitors, and temporary personnel, or a total of approximately 24 pounds of BOD_5 per day.

After construction is complete and Unit 1 is operating, the estimated hydraulic loading figures are as follows.

163 permanent personnel at 35 gpd	5,700 gpd
20 visitors and temporary personnel at 25 gpd	500 gpd
TOTAL	6,200 gpd

Biological loading will be approximately 0.075 pound per day of BOD_5 for permanent personnel and 0.045 pound per day of BOD_5 for visitors and temporary personnel or a total of approximately 13 pounds per day of BOD_5.

3.6.2 Solid Wastes

The solid wastes generated by the operation of Stanton Energy Center, Unit 1 will consist of fly ash, boiler hopper ash, flue gas desulfurization wastes, bottom ash and coal pulverizer rejects. These wastes will be stored onsite in an unlined landfill (combustion waste storage) area on the west side of the site. The quantities of waste produced will depend on the coal burned. The following quantities are based on a typical washed Illinois coal.

The fly ash will be collected by an electrostatic precipitator. The estimated production of fly ash is 56,700 tons/yr. The fly ash will be conveyed by vacuum to a fly ash storage silo. A bag filter will be employed to control fugitive emissions from the silo and vacuum system.

The fly ash which falls out in the boiler hopper will be conveyed to the fly ash storage silo by a branch of the fly ash vacuum transport system. Estimated production of boiler hopper ash is 3,000 tons/yr.

The scrubber sludge produced in the flue gas desulfurization (FGD) equipment is estimated at 111,300 tons/yr. The sludge from the FGD system will contain primarily calcium sulfate with some calcium sulfite, inerts, and unreacted limestone. The scrubber sludge will be dewatered by thickeners or liquid cyclones and vacuum filters to approximately 70 to 80 per cent solids. The reclaimed water will be returned for makeup to the scrubber loop. The dewatered sludge will be mixed with fly ash and trucked to the combustion waste storage area.

The bottom ash production is estimated at 14,900 tons/yr. The bottom ash will be hydraulically sluiced to a transfer tank and then slurried to bottom ash dewatering bins. The bottom ash will be dewatered in the bins and the reclaimed waters will be returned for use in bottom ash hydraulic transport. The bottom ash will be trucked from the dewatering bins to the combustion waste storage area.

Pulverizer rejects are primarily iron pyrites, hard rock, or slate.
The estimated rejects production rate is 3,800 tons/yr. The pulverizer | 5
rejects will be sluiced to the bottom ash transfer tank for disposal with the bottom ash.

The active combustion waste storage area at any one time will consist of an area of approximately 15 acres. The vegetation and topsoil from this area will be removed and the topsoil stockpiled separately for reuse. The conditioned sludge and bottom ash will be hauled to the area, deposited, and compacted with mechanical equipment. Drainage from the active combustion waste storage area will be intercepted by a drainage collection system and directed to the active combustion waste area runoff pond. This runoff pond will drain to the recycle basin. When this active area has been filled, it will be surfaced with the previously stockpiled topsoil to drain toward natural drainage systems in the area. This portion of land will be reclaimed by restoring vegetation. Conditioned sludge will be deposited and compacted in the new area. Drainage from this new area will be intercepted as described above. Figure 3.6-1 shows the combustion waste storage process. The process will be repeated until the entire designated combustion waste storage area has been utilized. The total waste storage require-
ment will be approximately 5,220 acre-feet for the 30-year life of Unit 1. | 5
The waste storage area consists of 312 acres. One-fourth of this area will be required for Unit 1. The remaining area is provided for ultimate site development.

66.92 High

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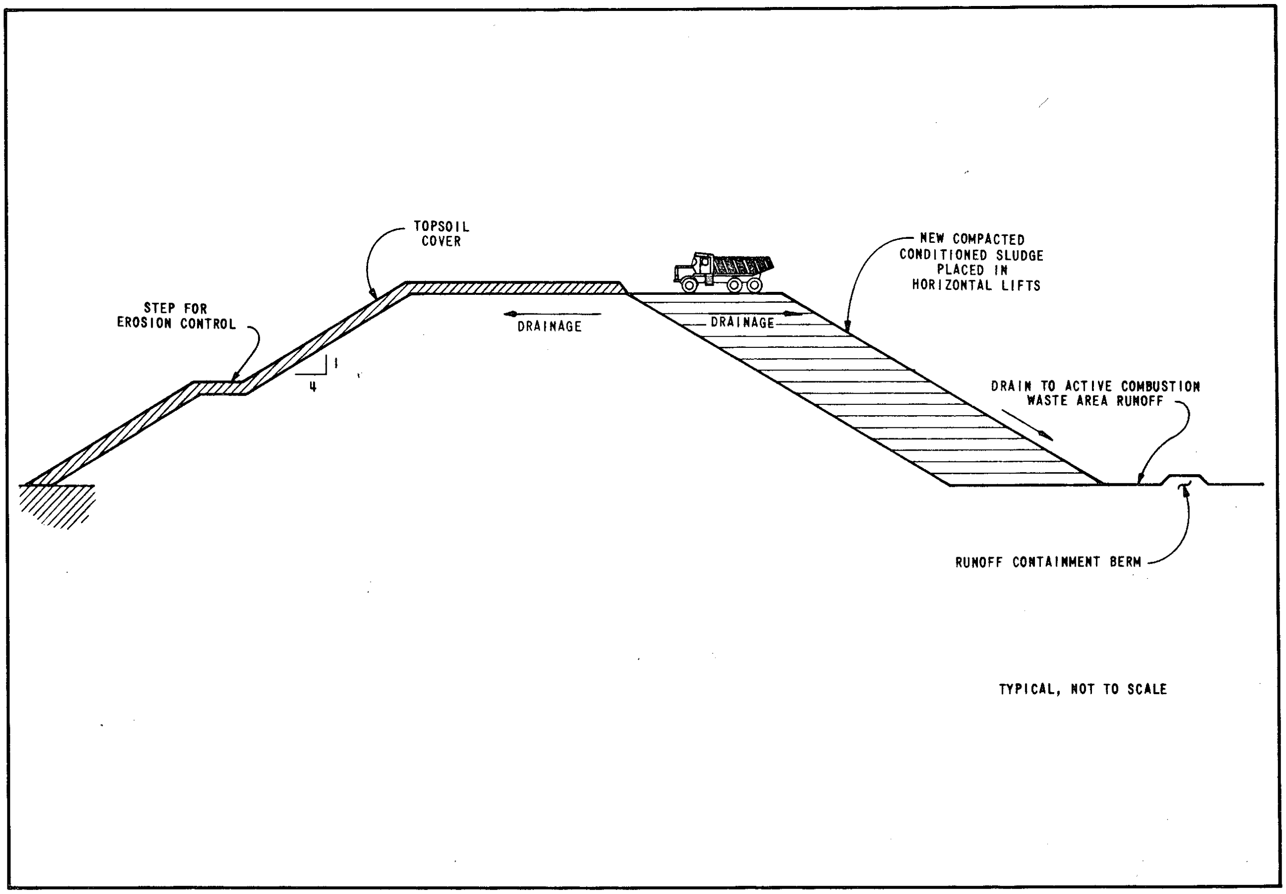

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FIGURE 3.6-1. COMBUSTION WASTE STORAGE FILL OPERATION

3.7 AIR EMISSIONS

3.7.1 Air Emission Types and Sources

The types and sources of air emissions are as follows.

(1) Fugitive dust from coal handling, limestone handling, lime han-
dling, fly ash handling, scrubber sludge disposal operations, and 5
traffic.

(2) Nitrogen oxides from the combustion process.

(3) Particulate from the combustion process.

(4) Sulfur dioxide from the combustion process.

(5) Combustion flue gases from the start-up auxiliary boiler.

3.7.2 Air Emission Controls

3.7.2.1 Fugitive Dust. The fugitive dust controls for coal handling and
limestone handling will include fabric filters, partially and totally RFM-1
enclosed conveyors, compaction, water and chemical sprays, and telescopic
chutes. Coal handling fugitive dust controls are described in Subsec-
tion 3.2.4. Limestone handling fugitive dust controls are described in 5
Subsection 3.9.4. Lime handling fugitive dust controls are described in
Subsection 3.9.6.

Another fugitive dust release point will be the fly ash transport system. Fly ash from the boiler hoppers and electrostatic precipitator hoppers will be transported to a fly ash storage silo by a vacuum type pneumatic system. The system will consist of vacuum pumps which will transport the fly ash to the fly ash storage silo and then vent through fabric filters. Estimated control efficiency is 99+ per cent. Estimated emission rates are presented in Section 5.5.

Other expected fugitive dust sources are traffic on limestone surfaced roads and scrubber sludge landfill operations. The control of this nuisance dust will be by spraying the areas with water or a dust palliative.

3.7.2.2 Nitrogen Oxides. In the combustion process, nitrogen oxides (NO_x) are formed in the high temperature regions of the boiler in and around the flame zone by oxidation of both atmospheric nitrogen and nitrogen in the fuel. Formation of NO_x can be reduced by lowering peak combustion temperatures by limiting the amount of excess air available to the fuel. 5

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NO_x will be controlled to meet the federal emission standards by utilizing features to minimize NO_x formation during combustion. These design features will include one or more of the following.

(1) Compartmented windbox (improved combustion control).

(2) Large furnace and widely spaced burners (reduced temperatures).

(3) Staged combustion.

The large furnace and widely spaced burners increase the burner firing zone absorption area and decrease peak combustion temperatures, thus minimizing NO_x formation.

The steam generators will be designed to operate so that the oxides of nitrogen emission rate will not exceed the federal emission standards of 0.60 lb NO_x per million Btu of heat input for bituminous coals, and will be guaranteed by the steam generator manufacturer.

3.7.2.3 <u>Particulate</u>. The principal particulate removal equipment will be an electrostatic precipitator. The electrostatic precipitator will be located directly downstream of the steam generator air heater. The design of the precipitator is based on a washed Appalachian coal as listed in Section 3.2. This particular coal results in a relatively large precipitator that will be capable of operating with numerous coals and still meet the new source performance standards of 0.03 lb particulate matter per million Btu heat input. The precipitator design will also include margins to help assure that the emission standards will be met under off-design operating conditions.

The design conditions for the electrostatic precipitator will be as follows.

(1) Flue gas flow at system inlet.

  (a) Mass flow rate--5,255,000 lbs/h.

  (b) Volumetric flow rate at 29.26 inch HgA and 278 F-- 5
  1,635,000 acfm.

(2) Flue gas temperature--278 F.

(3) Inlet dust loading at 278 F and 29.26 inch HgA--0.7 to 4.0 gr/acf. 5

(4) Outlet guarantee dust loading--0.013 gr/dscf.

(5) Particulate inlet--8.52 to 6.46 lb/10^6 Btu.

(6) Outlet particulate emission--0.03 lb/10^6 Btu.

(7) Chimney plume opacity limitation--20 per cent.

(8) Number of fields in the direction of gas flow--6.

(9) Net Specific Collecting Area, square feet per 1,000 acfm (based on design flow conditions)--743. 5

(10) Minimum Aspect Ratio--1.9.

The electrostatic precipitator will be capable of operating continuously and within particulate emission guarantees down to 20 per cent of unit load.

3.7.2.4 Sulfur Dioxide. The flue gas desulfurization system will consist of a multi-module wet limestone spray tower scrubber located downstream of the induced draft fans. The system will have three 50 per cent capacity modules with a bypass system. The system will be designed to limit sulfur dioxide emissions to 0.60 lbs per million Btu when total removal (coal washing and flue gas scrubbers) is less than 90 per cent (70 per cent minimum) and otherwise a removal efficiency of 90 per cent.

The design of the scrubber is based on an unwashed Illinois Basin coal as listed in Section 3.2. This particular coal is high in sulfur content and low in heating value and will result in a relatively large scrubber that will be capable of operating with numerous coals and still meet the new source performance standards. The scrubber design will also include margins to assure that the emission standards will be met under off-design operating conditions.

The design conditions for the flue gas scrubber will be as follows.

(1) Flue gas flow at scrubber inlet.

(a) Mass flow rate--5,118,000 lb/h.

(b) Volumetric flow rate at 30.30 inch HgA and 287 F--1,534,000 acfm. 5

(2) Flue gas inlet temperature--287 F.

(4) Outlet guarantee dust loading--0.013 gr/dscf.

(5) Particulate inlet--8.52 to 6.46 lb/10^6 Btu.

(6) Outlet particulate emission--0.03 lb/10^6 Btu.

(7) Chimney plume opacity limitation--20 per cent.

(8) Minimum number of fields in the direction of gas flow--6.

(9) Minimum Specific Collecting Area, square feet per 1,000 acfm (based on design flow conditions)--700.

(10) Minimum Aspect Ratio--2.0.

The electrostatic precipitator will be capable of operating continuously and within particulate emission guarantees down to 20 per cent of unit load.

3.7.2.4 Sulfur Dioxide. The flue gas desulfurization system will consist of a multi-module wet limestone spray tower scrubber located downstream of the induced draft fans. The system will have three 50 per cent capacity modules with a bypass system. The system will be designed to limit sulfur dioxide emissions to 0.60 lbs per million Btu when total removal (coal washing and flue gas scrubbers) is less than 90 per cent (70 per cent minimum) and otherwise a removal efficiency of 90 per cent.

see Next page

The design of the scrubber is based on an unwashed Illinois Basin coal as listed in Section 3.2. This particular coal is high in sulfur content and low in heating value and will result in a relatively large scrubber that will be capable of operating with numerous coals and still meet the new source performance standards. The scrubber design will also include margins to assure that the emission standards will be met under off-design operating conditions.

The design conditions for the flue gas scrubber will be as follows.

(1) Flue gas flow at scrubber inlet.

- (a) Mass flow rate--5,023,000 lb/h.
- (b) Volumetric flow rate at 30.30 inch HgA and 278 F-- 1,507,000 acfm.

(2) Flue gas inlet temperature--278 F.

(3) SO_2 inlet concentration--1.08 to 7.34 lbs/10^6 Btu.

(4) Guaranteed SO_2 outlet concentration--0.108 to 0.734 lb/10^6 Btu, respectively. 4 5

(5) Guaranteed removal efficiencies--90 per cent.

The flue gas will be discharged from the scrubber directly into the chimney without reheating.

3.7.2.5 Startup Auxiliary Boiler Flue Gas Emissions. An auxiliary boiler will be provided for the startup of Unit 1. The auxiliary boiler will be a packaged unit and will burn Number 2 fuel oil. The estimated maximum heat input rate to the auxiliary boiler will be 83 million Btu/h. 5 Based on typical No. 2 fuel oil properties of 19,430 Btu/lb, 0.003 lb sulfur/lb, 0.0002 lb nitrogen/lb, and then 0.0003 lb ash/lb; estimated auxiliary boiler emissions are presented in Table 3.7-1. The flue gas from the auxiliary boiler will be released from a stack on the roof of the Administration and Plant Services Building. The stack will be approximately 48 feet above grade. No equipment will be added to treat the auxiliary boiler flue gases for purposes of reducing emissions. It is anticipated that the auxiliary boiler will be used less than 150 hours per year for Unit 1 alone and very seldom if at all after additional units are installed.

3.7.3 Combustion Gas Discharge

The combustion gas from the steam generator will be discharged through a concrete chimney with a brick liner. The chimney will have a height of 550 feet and an inside diameter at the top of 19 feet. The chimney will be designed to handle a gas flow of 1,420,000 acfm at 127 F resulting in an exit velocity of 83 feet per second.

3.7.4 Best Available Control Technology (BACT)

3.7.4.1 BACT Evaluation Fuels. The coal supply for the Stanton Energy Center Unit 1 has not been committed and it will probably vary over

(3) SO_2 inlet concentration--6.19 to 8.25 lbs/10^6 Btu.

(4) Guaranteed SO_2 outlet concentration--0.619 to 0.825 lb/10^6 Btu, respectively. 4

(5) Guaranteed removal efficiencies--90 per cent.

The flue gas will be discharged from the scrubber directly into the chimney without reheating.

3.7.2.5 Startup Auxiliary Boiler Flue Gas Emissions. An auxiliary boiler will be provided for the startup of Unit 1. The auxiliary boiler will be a packaged unit and will burn Number 2 fuel oil. The estimated maximum heat input rate to the auxiliary boiler will be 92 million Btu/h. Based on typical No. 2 fuel oil properties of 19,430 Btu/lb, 0.003 lb sulfur/lb, 0.0002 lb nitrogen/lb, and then 0.0003 lb ash/lb; estimated auxiliary boiler emissions are presented in Table 3.7-1. The flue gas from the auxiliary boiler will be released from a stack on the roof of the Administration and Plant Services Building. The stack will be approximately 48 feet above grade. No equipment will be added to treat the auxiliary boiler flue gases for purposes of reducing emissions. It is anticipated that the auxiliary boiler will be used less than 150 hours per year for Unit 1 alone and very seldom if at all after additional units are installed.

3.7.3 Combustion Gas Discharge

The combustion gas from the steam generator will be discharged through a concrete chimney with a brick liner. The chimney will have a height of 550 feet and an inside diameter at the top of 19 feet. The chimney will be designed to handle a gas flow of 1,420,000 acfm at 127 F resulting in an exit velocity of 83 feet per second.

3.7.4 Best Available Control Technology (BACT)

3.7.4.1 BACT Evaluation Fuels. The coal supply for the Stanton Energy Center Unit 1 has not been committed and it will probably vary over the life of the unit. Therefore, the evaluation of flue gas cleaning equipment was based on three typical coal analyses. The analyses are shown in Table 3.7-2. The coals are all bituminous and were identified as Illinois, Medium Sulfur Appalachian and Higher Sulfur Appalachian. The ranges of these coals encompass the ranges of the coals being considered for Unit 1 of the Stanton Energy Center and should also be typical of possible future coals.

3.7.4.2 Nitrogen Oxide BACT. The current NO_x New Source Performance Standard (NSPS) for bituminous coal is 0.60 $lb/10^6$ Btu, which the boiler manufacturer will guarantee. Presently, the greatest promise for NO_x control lies in preventing NO_x formation in the furnace. However, the currently implemented methods of reducing NO_x released to the atmosphere by utility boilers cannot achieve more than 50 per cent reduction. From what is known about combustion control approaches today, it appears unlikely that they alone are feasible for meeting more stringent NO_x emissions standards than those required by the NSPS.

Post-combustion NO_x controls are necessary to achieve extremely low NO_x emission levels. The post-combustion process closest to commercial acceptance for utility application is the selective catalytic reduction (SCR) of NO_x with ammonia. This process has the most R&D attention, initially in Japan and mainly for dealing with NO_x from low-sulfur fuel oil and natural gas, which are widely used in that country. The major problem is to adapt the process to coal-fired applications, where higher levels of SO_2 and particulate matter can easily impair performance. The SCR application to coal-fired NO_x control is characterized by many unanswered questions and unresolved issues. System costs are therefore difficult to assess. Current estimates are from $75 to $200 per kilowatt of plant capacity, which would be a significant portion of total plant costs. Because of the high capital cost to install SCR, an unproven technology for coal fired NO_x reduction, it will not be used at the Stanton Energy Center Unit 1. NO_x control will be by combustion control.

3.7.4.3 Particulate Removal BACT. Particulate emission control is required to comply with the emission standards of 0.03 lb per million Btu heat input. Two basic types of particulate removal systems capable of meeting this New Source Performance Standards have been applied to large, coal-fired boilers: electrostatic precipitators and fabric filters.

Electrostatic precipitators of the size and efficiency required to meet the emission limitations applicable to the Stanton Energy Center Unit 1 have been proven in operation. Electrostatic precipitators utilize transformer-rectifiers to energize high voltage discharge electrodes which produce a dc high-voltage electrical field between the discharge electrodes and the grounded collecting electrodes. Particulates entering the electric field acquire a charge and migrate to the collecting electrodes. A layer of collected particles forms on the collecting electrodes and is removed periodically by rapping the electrodes. The collected particulates drop into hoppers below the precipitator and are periodically removed by the fly ash handling system.

Electrostatic precipitators are generally categorized as being hot or cold, depending upon their location in the flue gas stream. Hot precipitators are located on the hot side of the air heaters (between the economizer and the air heater), where the operating temperatures vary from 600 to 900 F. Cold precipitators are located on the cold side of the air heaters (between the air heater and the chimney), where the operating temperatures generally vary from 250 to 350 F. A hot precipitator will not be considered for Stanton Energy Center Unit 1 because it has greater thermal losses, is subject to greater thermal stresses than the cold side precipitator, and has exhibited significant operating problems which have resulted in poor performance at several installations. A cold side precipitator is feasible for use on this unit.

Fabric filters have been used extensively in small industrial applications, but, until recently, have not been used in utility boiler applications. Short filter bag life was the primary reason for their unsuitability. Recently, however, a large amount of work has been performed by fabric filter manufacturers, electric utilities, and textile manufacturers to correct the most common causes of bag failure and to develop more durable filter fabrics. Consequently, fabric filters are becoming more prevalant in the utility market, especially for small and medium-size units.

Fabric filters utilize fabric bags as filters to collect the particulate. Particulate-laden gas enters one of several fabric filter compartments and passes through the filter bags. The collected particulate forms a cake on the bags which enhances the filtering efficiency. At predetermined time intervals or on a high differential pressure signal, the bags are cleaned of most of the collected particulate by reverse air-deflation, shaking, a rapid pulse of air, or a combination of the first two actions, leaving an optimum dust layer on the bags to aid in the filtration process. The particulates are collected in hoppers below the fabric filter housing and are periodically removed from the hoppers by conventional fly ash removal systems.

Cold side electrostatic precipitators and fabric filters were evaluated using fly ash production rates and removal efficiencies presented in Table 3.7-3. The details of the evaluation are shown in Appendix 3.7A. Different size precipitators could be used for each of the coals considered to meet required removal efficiencies. Fabric filter collection systems are approximately the same size for all three coals.

A comparative cost evaluation of these two types of particulate removal systems is shown in Table 3.7-4. A cold side electrostatic precipitator is the most economical particulate removal system for all three coals considered.

A cold side electrostatic precipitator is the most advantageous combustion gas particulate removal system for the Stanton Energy Center Unit 1. An evaluation of available systems and costs indicates that this is the most reliable and economical particulate removal system. In addition, it has the most operating experience. Electrostatic precipitators for utility boilers the size of the proposed unit have been in use for many years and the reliability of cold side precipitators on medium and high sulfur fuels has been demonstrated.

3.7.4.4 Desulfurization BACT. Research, testing, and development of flue gas desulfurization (FGD) has produced over 200 desulfurization processes. Only seven processes have been commercially applied: lime, limestone, spray absorber, double alkali, soda ash, magnesium oxide, and Wellman-Lord processes. One other process, flue gas sparging (Chiyoda), is being offered, but it has not been proven in a full-scale utility application. Although the majority of the FGD systems which have been purchased and planned utilize lime/limestone technology, research is being conducted toward the development of newer, more sophisticated systems capable of the recovery of usable byproducts from the flue gas cleaning wastes. Table 3.7-5 presents a summary of the current status of FGD systems on utility applications in the United States.

FGD systems are divided into two basic categories, throwaway processes and recovery processes. The categories refer to the end product derived from the sulfur dioxide removed from the flue gas. In throwaway processes, the end product has no commercial value and, like ash, must be disposed of in ponds or landfills. Recovery processes yield a salable material such as gypsum, sulfur, sulfuric acid, or fertilizer base compounds.

The advantages and disadvantages of these eight FGD processes are presented in Table 3.7-6. A more detailed discussion of these eight processes are presented in Appendix 3.7B. To be considered a feasible alternative for Stanton Energy Center Unit 1, the process must meet the following criteria.

(1) Demonstrated technical feasibility.
(2) Advanced level of availability.
(3) Acceptance by the utility industry.
(4) Favorable economic impact.
(5) Acceptable environmental impact of waste disposal or a marketable end product.
(6) Capable of meeting emission rates for a wide range of coals.

Based on the selection criteria and the advantages and disadvantages of the eight processes listed in Table 3.7-6, the lime and limestone scrubbers are considered feasible alternatives for the proposed facility. Both lime and limestone are available in the counties surrounding the site. Limestone, a naturally occurring mineral, is mined extensively in Florida. Lime, which is produced by calcining limestone, is also available from in-state and out-of-state producers. With an adequate supply of both additives and the extensive history of utility operation, both lime and limestone additive processes are considered to be feasible alternatives.

Lime and limestone scrubbers were evaluated using the sulfur dioxide production rates and removal requirements in Table 3.7-7. Details of the evaluation are presented in Appendix 3.7B.

A comparative cost evaluation of these two types of scrubbers is shown in Table 3.7-8. Limestone scrubbers are the most economical scrubbers for all three coals considered.

A limestone scrubber is the most advantageous combustion gas desulfurization system for the proposed facility. An evaluation of available systems and costs indicates that this is the most reliable and economical desulfurization system.

The limestone scrubber for Unit 1 will be designed for an unwashed Illinois coal with properties similar to the Illinois coal used for the BACT evaluation. Therefore, cost differences between limestone and lime scrubbers shown for the Illinois coal in Table 3.7-8 are representative of the differences that would be expected for the actual design coal. The design scrubber removal is 90 per cent. If scrubber efficiencies much greater than this were required on a continuous basis, limestone packed towers or a lime scrubber may be required. Both packed towers and lime are more expensive. The relative costs for lime and limestone FGD systems are shown in Table 3.7-8. The 90 per cent removal design for the scrubber will meet new source performance standards. Greater removal efficiency requirements would cause substantial cost increases and may result in decrease unit availability.

3.7.4.5 Best Available Control Technology Data. The completed form entitled Best Available Control Technology Data from the Site Certification Guidelines is shown in Table 3.7-9.

TABLE 3.7-1. ESTIMATED AUXILIARY BOILER FLUE GAS EMISSIONS

	Auxiliary Boiler Emission Rates	Maximum Auxiliary Boiler Emission Rates	Expected Annual Auxiliary Boiler Emission
	$lb/10^6$ Btu	lb/h	lb
Sulfur Dioxide	.31	25.4	2,201
Nitrogen Oxides	.16	13.1	1,135
Particulate Matter	.015	1.25	110

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TABLE 3.7-2. BACT EVALUATION FUEL ANALYSES

Description	Coal: Illinois Coal* Average	Illinois Coal* Range	Medium Sulfur Appalachian Coal Average	Medium Sulfur Appalachian Coal Range	Higher Sulfur Appalachian Coal Average	Higher Sulfur Appalachian Coal Range
Proximate Analysis, per cent						
Moisture	10.1	6.0 - 15.0	6.0	3.5 - 8.0	6.0	3.5 - 8.0
Volatile matter	33.8		33.0		40.0	
Fixed carbon	47.1		54.5		48.0	
Ash	9.0	7.5 - 14.0	6.5	6.0 - 12.0	6.0	6.0 - 13.5
Ultimate Analysis, per cent						
Carbon	65.5		73.3		74.5	
Hydrogen	4.5		4.9		5.0	
Nitrogen	0.5		1.3		1.4	
Chlorine	0.14	0.08 - 0.20	0.02	0.01 - 0.05	0.01	0.01 - 0.05
Sulfur	2.10**	2.0 - 4.50**	0.86	0.75 - 1.50	1.40	1.40 - 2.40
Oxygen	8.16		7.12		5.69	
Ash	9.0	7.5 - 14.0	6.5	6.0 - 12.0	6.0	6.0 - 13.5
Moisture	10.1	6.0 - 15.0	6.0	3.5 - 8.0	6.0	3.5 - 8.0
Heating Value (Btu/lb)	11,730	10,500 - 12,000	13,125	12,000 - 13,600	12,840	11,750 - 13,600

*Analysis is for washed Illinois coal.

**Raw coal maximum and average sulfur contents are approximately 5.46 and 2.55 per cent, respectively. The minimum and average heating values are 8,925 and 10,000 Btu/lb, respectively.

TABLE 3.7-3. PARTICULATE PRODUCTION RATES AND REMOVAL REQUIREMENTS

Parameter	Illinois Coal		Medium Sulfur Appalachian Coal		High Sulfur Appalachian Coal	
	Maximum	Average	Maximum	Average	Maximum	Average
Fly ash production rate, pounds per 10^6 Btu	10.67	6.14	8.00	3.96	9.19	3.74
Allowable particulate emission, pounds per 10^6 Btu	0.03	0.03	0.03	0.03	0.03	0.03
Particulate removal rate, pounds per 10^6 Btu	10.64	6.11	7.97	3.93	9.16	3.71
Particulate removal efficiency, per cent	99.7	99.5	99.6	99.2	99.7	99.2

TABLE 3.7-4. COMPARATIVE COSTS FOR PARTICULATE REMOVAL EQUIPMENT

	Electrostatic Precipitator			
	Illinois Coal $1,000	Medium Sulfur Appalachian Coal $1,000	High Sulfur Appalachian Coal $1,000	Fabric Filter $1,000
Capital Costs				
Material and erection (1980 costs)	Base	1,530	1,711	5,924
Escalation	Base	718	803	2,780
Sales tax	Base	90	101	348
Interest during construction	Base	142	159	551
Indirect cost	Base	446	499	1,728
Differential capital cost	Base	2,926	3,273	11,331
Levelized Operating Costs				
Operating personnel	Base	Base	Base	Base
Maintenance	Base	Base	Base	715
Demand charge	59	112	119	Base
Energy charge	Base	86	96	434
Comparative operating cost	59	198	215	1,149
Differential operating cost	Base	139	156	1,090
Annual Costs				
Fixed charges	Base	298	334	1,156
Levelized operating costs	Base	139	156	1,090
Comparative annual costs	Base	437	490	2,246

TABLE 3.7-5. STATUS OF GAS DESULFURIZATION PROCESSES ON COAL-FIRED STEAM ELECTRIC GENERATING UNITS IN THE UNITED STATES

	Throwaway Processes					Recovery Process		
Scrubber Status	Lime	Limestone	Spray Absorber	Soda Ash	Double-Alkali	Magnesium Oxide	Wellman-Lord	Total
Operational								
MW	8,801	11,464	110	925	1,181	0	1,540	24,021
Per cent of total	36	48	1	4	5	0	6	100
Under construction or contracts awarded								
MW	3,836	17,390	3,313	330	842	724	534	26,969
Per cent of total	14	65	12	1	3	3	2	100
								50,990 MW

Reference: EPA Utility FGD Survey: October-December 1980, USEPA, EPA-600/7-81-012a, January, 1981.

TABLE 3.7-6. FGD PROCESS ADVANTAGES AND DISADVANTAGES

Process	Advantages	Disadvantages
Throwaway Processes		
Lime	• Extensive operating experience. • Numerous qualified suppliers. • Stable waste product produced. • Relatively low cost additives.	• Scaling and plugging potential throughout system. • Relatively high L/G required. • Large quantities of waste products produced.
Limestone	• Extensive operating experience. • Numerous qualified suppliers. • Stable waste product produced. • Relatively low cost additives.	• Scaling and plugging potential throughout system. • Relatively high L/G required. • Large quantities of waste products produced.
Spray Absorber	• Decreased pumping requirements. • No scaling conditions. • Decreased flue gas pressure drop. • Waste products in a dry state.	• Low additive utilization. • Limited SO_2 removal efficiency. • Limited operating experience on full scale system.
Double Alkali	• Limited scaling potential. • Compared with soda ash, has lower additive costs. • Relatively low L/G required.	• Limited operating experience. • Incomplete sodium recovery. • Large quantities of waste products produced. • Storage of two additives required.
Soda Ash	• High SO_2 removal efficiency. • No slurry pumping. • Simple additive preparation equipment. • Lower capital costs.	• Waste disposal extremely difficult. • High additive costs. • Large quantities of waste products produced.

TABLE 3.7-6 (Continued). FGD PROCESS ADVANTAGES AND DISADVANTAGES

Process	Advantages	Disadvantages
Chiyoda	• Highly oxidized waste product. • High additive utilization. • Low cost additive. • Decreased pumping requirements.	• Relatively high flue gas pressure drop. • Limited operating experience. • Large quantities of waste products produced.
Recovery Processes		
Magnesium Oxide	• High SO_2 removal efficiency. • Nonscaling conditions in scrubber. • Marketable end product.	• Low availability in pilot tests. • Low additive regeneration efficiency. • High capital cost.
Wellman-Lord	• A clear scrubbing solution. • No slurry pumping in scrubber. • Nonscaling conditions in scrubber. • Marketable end product.	• Complex equipment train. • Requires highly trained operators. • High capital cost.

TABLE 3.7-7. SULFUR DIOXIDE PRODUCTION RATES AND REMOVAL REQUIREMENTS

Parameter	Illinois Coal		Medium Sulfur Appalachian Coal		Higher Sulfur Appalachian Coal	
	Maximum	Average	Maximum	Average	Maximum	Average
SO_2 production from raw coal, pounds per 10^6 Btu (100 per cent conversion of sulfur to sulfur dioxide)	12.24	5.11	2.50	1.31	4.09	2.18
Overall SO_2 removal requirements to meet allowable emission rate (based on raw coal), per cent	91	89	76	70	86	73
Allowable SO_2 emission rate (based on raw coal), pounds per 10^6 Btu	1.20	0.60	0.60	0.39	0.60	0.60
Required SO_2 reduction, pounds per 10^6 Btu	11.04	4.51	1.90	0.92	3.49	1.58
Sulfur reduction resulting from coal washing, pounds per 10^6 Btu (as SO_2)	3.67*	1.53*	--	--	--	--
SO_2 reduction required in FGD system, pounds per 10^6 Btu	7.37	2.98	1.90	0.92	3.49	1.58
FGD system removal efficiency, per cent	86**	84**	76	70	86	73

*The SO_2 reduction resulting from coal washing represents the difference in the SO_2 production estimated for the raw coal and the SO_2 production based on the Illinois washed coal analysis.

**FGD system removal efficiency is determined as the SO_2 reduction required for the washed Illinois coal to comply with the total reduction required for the raw coal.

TABLE 3.7-8. COMPARATIVE COSTS FOR DESULFURIZATION EQUIPMENT

	Illinois Coal		Medium Sulfur Appalachian Coal		High Sulfur Appalachian Coal	
	Limestone $1,000	Lime $1,000	Limestone $1,000	Lime $1,000	Limestone $1,000	Lime $1,000
Capital Costs						
Scrubber material and erection	1,370	400	900	Base	1,840	900
Additive equipment	1,620	2,590	450	Base	1,110	760
Waste handling equipment	820	750	20	Base	250	180
Subtotal	3,810	3,790	1,370	Base	3,200	1,840
Escalation	1,790	1,780	640	Base	1,500	860
Escalated Cost	5,600	5,570	2,010	Base	4,700	2,700
Sales tax	220	220	80	Base	190	110
Interest during construction	390	390	140	Base	330	190
Indirect costs	700	690	250	Base	590	340
Comparative capital cost	6,910	6,870	2,480	Base	5,810	3,340
Levelized Operating Costs						
Demand charge	258	136	97	Base	229	126
Energy charge	693	404	222	Base	659	395
Additive	1,432	9,596	Base	2,007	391	3,953
Waste disposal	498	329	46	Base	139	60
Comparative operating costs	2,881	10,465	365	2,007	1,418	4,534
Differential operating costs	2,516	10,100	Base	1,642	1,053	4,169
Annual Costs						
Fixed charges	705	701	253	Base	593	341
Operating costs	2,516	10,100	Base	1,642	1,053	4,169
Comparative annual cost	3,221	10,801	253	1,642	1,646	4,510
Differential comparative annual cost	2,968	10,548	Base	1,389	1,393	4,257

TABLE 3.7-9. BEST AVAILABLE CONTROL TECHNOLOGY DATA

A. Emission Limitations For Any Pollutants Emitted From The Source Pursuant To 17-2, F.A.C.?

Yes (X) No ( )

POLLUTANT	RATE OF CONCENTRATION
Particulates	0.1 #/MBtu
SO_2	1.2 #/MBtu
NO_x	0.70 #/MBtu

B. Are Standards of Performance For New Stationary Sources Pursuant To 40 C.F.R. Part 60 Applicable To The Source?

Yes (X) No ( )

POLLUTANT	RATE OF CONCENTRATION
Particulates (TSP)	0.03 #/MBtu
SO_2	1.2 #/MBtu*
NO_x	0.60 #/MBtu

C. Has EPA Declared The Best Available Control Technology For This Class Of Sources? (If Yes Attach Copy)

Yes ( ) No (X)

POLLUTANT	RATE OF CONCENTRATION

*Plus the per cent removal requirements of the applicable New Source Performance Standard.

TABLE 3.7-9 (Continued). BEST AVAILABLE CONTROL TECHNOLOGY DATA

D. What Emission Levels Do You Propose As Best Available Control Technology?

POLLUTANT	RATE OF CONCENTRATION
TSP	0.03 #/MBtu
SO_2	New Source Performance Standard
NO_x	0.60 #/MBtu

E. Describe the Control Technology Proposed.

1.	Control Device:	Electrostatic Precipitator	Wet Limestone Flue Gas Scrubber	Coal Wash Facility* at Coal Mine	
2.	Efficiency:	99.61 per cent	90 per cent	Coal supply dependent*	
3.	Capital Cost:	$13,250,000 (1981 dollars)	$20,140,000 (1981 dollars)	Coal supply dependent*	
4.	Life:	35 years	35 years	Coal supply dependent*	5
5.	Operating Cost:*	$1,200,000/yr	$5,400,000/yr	Coal supply dependent*	
6.	Energy: (at maximum capability)	3.5 MW	3.8 MW	Coal supply dependent*	
7.	Maintenance Cost:**	$1,300,000/yr	$2,000,000/yr	Coal supply dependent*	

8. Stack Parameters:

a. Height: 550 Ft. b. Diameter: 19 Ft.

c. Flow Rate: 1,420,000 CFM d. Temperature: 127 F

e. Velocity: 83 FPS

*The facilities used to wash the coal and reduce the sulfur dioxide production rate will be owned and operated by the coal supplier. These parameters, if a washed coal is purchased, will be dependent on the specifications of the coal selected. 5

**Based on operation with design basis coal for respective component, 1981 dollar values. 5

TABLE 3.7-9 (Continued). BEST AVAILABLE CONTROL TECHNOLOGY DATA

9. Fuels:*

	Hourly Use lb AVG.	Hourly Use lb MAX.	Hourly Heat Input 10^6 Btu AVG.	Hourly Heat Input 10^6 Btu MAX.	
Washed Illinois Basin Coal	222,500	339,020	2,760	4,136	
Washed Appalachian Coal	212,200	320,620	2,760	4,136	
Unwashed Illinois Basin Coal	250,800	379,450	2,760	4,136	4 5
Washed Illinois Basin Coal	256,740 (300,330)	399,610 (489,590)	2,760	4,136	
No. 6 Fuel Oil (startup fuel)	14,700	23,790	269	435	

TYPE	DENSITY lb/ft^3	%S	%N	%ASH	
Washed Illinois Basin Coal	84	3.1	1.3	8.5	
Washed Appalachian Coal	84	.82	1.49	11.0	
Unwashed Illinois Basin Coal	84	4.0	1.3	18.5	4 5
Washed Illinois Basin Coal	84	3.8 (5.0)	1.5	12.5	
No. 6 Fuel Oil (startup fuel)	61.1	2.5	0.1	0.5	

*Main coal to be burned has not been selected. The first three coals listed are design basis coals for the steam generator, particulate removal equipment and scrubber, respectively. 4
These coal selections for design basis result in equipment capable of burning numerous coals and meeting NSPS. Coal properties listed are maximum values. Refer to Table 3.2-1 for typical values and ranges. Also listed is the coal which results in the greatest SO_2 emission rate of all the coals bid for supply to Stanton 4
Energy Center Unit 1 which can meet NSPS. The numbers in parentheses for this coal are the raw (unwashed) coal properties. The washed minimum heating value is 10,350 Btu/lb while the raw minimum heating value is 8,500 Btu/lb. 5

TABLE 3.7-9 (Continued). BEST AVAILABLE CONTROL TECHNOLOGY DATA

9. Fuels:*

	Hourly Use lb AVG.	Hourly Use lb MAX.	Hourly Heat Input 10^6 Btu AVG.	Hourly Heat Input 10^6 Btu MAX.
Washed Illinois Basin Coal	222,500	339,020	2,760	4,136
Washed Appalachian Coal	212,200	320,620	2,760	4,136
Unwashed Illinois Basin Coal	250,800	379,450	2,760	4,136
Unwashed Illinois Basin Coal	250,900	382,500	2,760	4,136
No. 6 Fuel Oil (startup fuel)	14,700	23,790	269	435

4

TYPE	DENSITY lb/ft^3	%S	%N	%ASH
Washed Illinois Basin Coal	84	3.1	1.3	8.5
Washed Appalachian Coal	84	.82	1.49	11.0
Unwashed Illinois Basin Coal	84	4.0	1.3	18.5
Unwashed Illinois Basin Coal	84	4.46	1.48	12.9
No. 6 Fuel Oil (startup fuel)	61.1	2.5	0.1	0.5

4

10. Wastes Generated: Based on Typical Washed Illinois Coal

Pulverizer Rejects	4,100	tons/yr
Bottom Ash	14,900	tons/yr
Fly Ash	56,700	tons/yr
Scrubber Solids	111,300	tons/yr
Total	187,000	tons/yr

*Main coal to be burned has not been selected. The first three coals listed are design basis coals for the steam generator, particulate removal equipment and scrubber, respectively. These coal selections for design basis result in equipment capable of burning numerous coals and meeting NSPS. Coal properties listed are maximum values. Refer to Table 3.2-1 for typical values and ranges. Also listed is the coal which results in the greatest SO_2 emission rate of all the coals bid for supply to Stanton Energy Center Unit 1. 4

TABLE 3.7-9 (Continued). BEST AVAILABLE CONTROL TECHNOLOGY DATA

10. Wastes Generated: Based on Typical Washed Illinois Coal

Pulverizer Rejects	3,800	tons/yr
Bottom Ash	12,200	tons/yr
Fly and Boiler Hopper Ash	48,400	tons/yr 5
Scrubber Solids	201,000	tons/yr
Total	265,400	tons/yr

Disposal Method: Truck haul to onsite landfill

Cost of Disposal: \$740,000/yr (1981 dollar values) 5

F. Show Derivation of Efficiency Estimation.

Electrostatic Precipitator - particulate input - 8.52 $lb/10^6$ Btu

particulate outlet - 0.03 $lb/10^6$ Btu

$$Eff = \frac{8.52\ lb/10^6\ Btu - 0.03\ lb/10^6\ Btu}{8.52\ lb/10^6\ Btu} \times 100\% = 99.65\%$$

For design basis coal-Washed Appalachian, this coal results in precipitator designed to handle other coal and emit 0.03 lb/ 10^6 Btu or less

Coal Wash Facilities and Wet Limestone Scrubber

Raw coal potential SO_2 production rate--11.76 $lb/10^6$ Btu

BACT SO_2 stack emission*--1.176 $lb/10^6$ Btu 5

$$\text{Overall effect} = \frac{11.76\ lb/10^6\ Btu - 1.176\ lb/10^6\ Btu}{11.76\ lb/10^6\ Btu} = 90 \text{ per cent}$$

Based on NSPS 90 per cent removal is required for emission of greater than 0.60 $lb/10^6$ Btu up to 1.2 $lb/10^6$ Btu - 90 per cent removal is required. 4 5

G. An 8-1/2 x 11 inch Flow Diagram Which Will, Identify the Individual Operations and/or Processes. Indicate Where Raw Materials Enter, Where Solid and Liquid Waste Exist, Where Gaseous Emissions and/or Airborne Particles Are Evolved (see Figure 3.7-1).

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*Maximum 3-hour stack emissions will require further reductions to 1.14 lb per 10^6 Btu for increment protection. The sulfur dioxide emission controls as designed are capable of achieving this level of control. 5

TABLE 3.7-9 (Continued). BEST AVAILABLE CONTROL TECHNOLOGY DATA

Disposal Method: Truck haul to onsite landfill

Cost of Disposal: \$520,000/yr (1981 dollar values)

F. Show Derivation of Efficiency Estimation.

Electrostatic Precipitator - particulate input - 8.52 lb/10^6 Btu

particulate outlet - 0.03 lb/10^6 Btu

$$\text{Eff} = \frac{8.52 \text{ lb}/10^6 \text{ Btu} - 0.03 \text{ lb}/10^6 \text{ Btu}}{8.52 \text{ lb}/10^6 \text{ Btu}} \times 100\% = 99.65\%$$

For design basis coal-Washed Appalachian, this coal results in precipitator designed to handle other coal and emit 0.03 lb/10^6 Btu or less

Scrubber - SO_2 input - 8.25 lb/10^6 Btu 4

Based on NSPS 90 per cent removal is required for emission of greater than 0.60 lb/10^6 Btu up to 1.2 lb/10^6 Btu - 90 per cent removal is required for unwashed Illinois coal which is worst coal for scrubber of the coals bid. 4

G. An 8-1/2 x 11 inch Flow Diagram Which Will, Identify the Individual Operations and/or Processes. Indicate Where Raw Materials Enter, Where Solid and Liquid Waste Exist, Where Gaseous Emissions and/or Airborne Particles Are Evolved (see Figure 3.7-1).

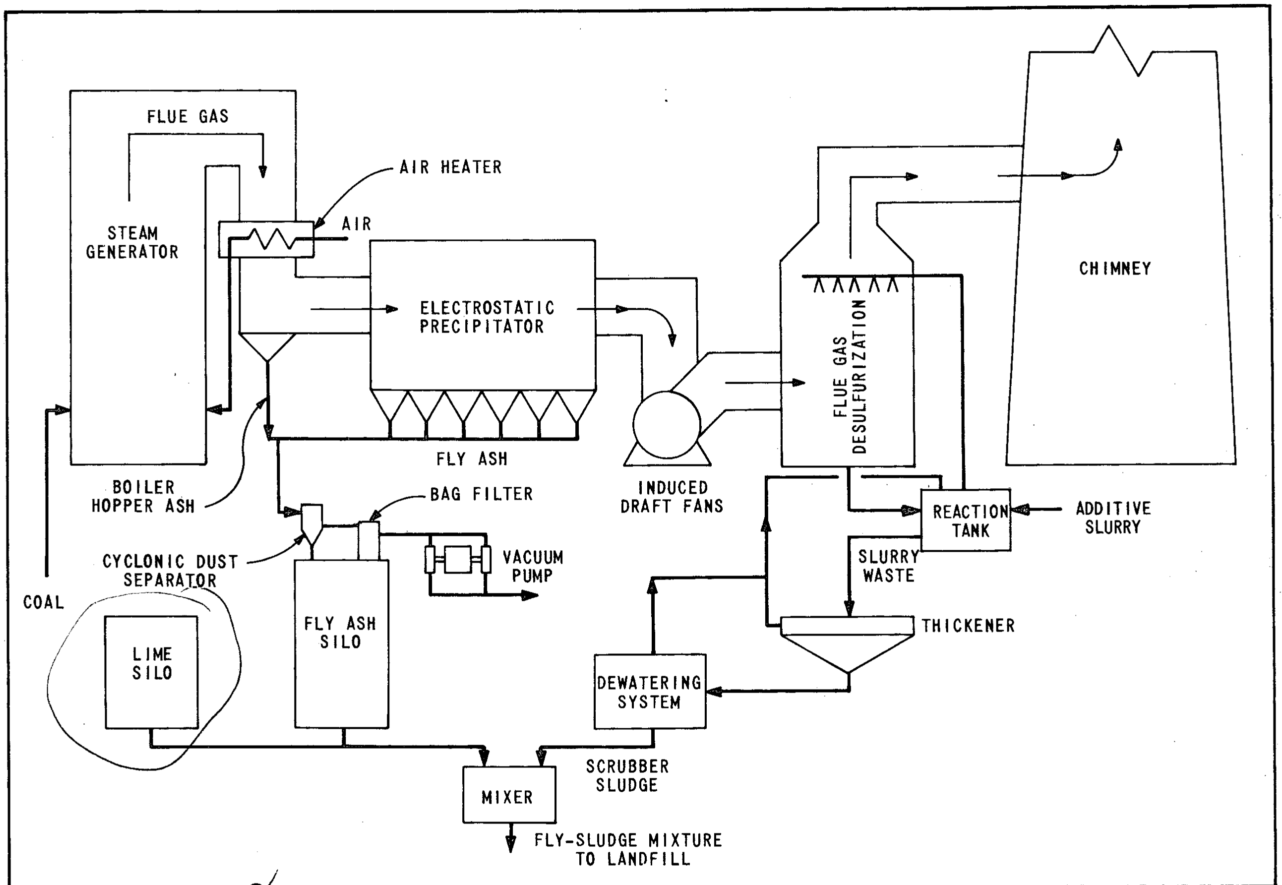

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FIGURE 3.7-1. FLUE GAS CLEANING FLOW DIAGRAM

APPENDIX 3.7A

ANALYSIS OF PARTICULATE REMOVAL SYSTEMS

APPENDIX 3.7A
ANALYSIS OF PARTICULATE REMOVAL SYSTEMS

3.7A.1 INTRODUCTION

This appendix discusses the alternative methods of particulate removal considered for Stanton Energy Center Unit 1 and their feasibility for use on the project.

3.7A.2 REQUIREMENTS OF PARTICULATE REMOVAL SYSTEM

(1) The particulate removal system shall be capable of removing particulate such that Florida Ambient Air Standards and New Source Performance Standards (NSPS) are met. The emission limitations in NSPS are more restrictive than Florida Ambient Air standards and therefore shall prevail. NSPS standards are as follows.

  (a) Particulate emission rates are limited to 0.03 pound per million Btu heat input.

  (b) Opacity is limited to 20 per cent, except for one 6-minute period per hour of not more than 27 per cent opacity.

  The production rates and removal efficiencies for the three coals considered are listed in Table 3.7A-1.

(2) The operating reliability of the particulate removal system must be such that the generating capability of the unit would not be limited by the particulate removal system.

(3) The particulate removal system must be applicable to any of the coals under consideration.

3.7A.3 ALTERNATE PARTICULATE REMOVAL SYSTEMS

The demonstrated methods of removing particulate matter from gas streams on coal-fired generating plants are as follows.

(1) Electrostatic precipitators.

(2) Fabric filters.

(3) Wet particulate scrubbers.

3.7A.3.1 Electrostatic Precipitators

Electrostatic precipitators of the size and efficiencies required for Unit 1 have been proven in operation on similar sized utility power plants firing the types of coal under consideration. This particulate removal process is the most widely used on large units at the present time, especially when high removal efficiencies are required.

Electrostatic precipitators utilize transformer-rectifiers to energize discharge electrodes which produce a dc high voltage electrical field between the discharge electrodes and the grounded collecting electrodes. Particulates entering the electrical field acquire a charge and migrate to the collecting electrodes. A layer of collected particles forms on the collecting electrodes and is removed periodically by rapping the electrodes. The collected particulates drop into hoppers below the precipitator and are periodically removed by the fly ash handling system.

The physical size of an electrostatic precipitator is determined by the required specific collection area (SCA) and gas volume to be treated. Design of precipitators is determined by the particulate and flue gas properties, gas flow, and the required collection efficiency. The most significant particulate property affecting precipitator design is fly ash resistivity which varies with the moisture content, the chemical composition, and the temperature of the fly ash in the flue gas. Operation also depends on the accuracy of precipitator electrode alignment, uniformity, and smoothness of gas flow through the precipitator, rapping of the electrodes, and the size and electrical stability of the transformer-rectifiers.

Electrostatic precipitators are generally categorized as being either hot or cold depending upon their location. Hot precipitators are located upstream of the air heaters where the operating temperatures are in the range of 600 to 900 F. Cold precipitators are located downstream of the air heaters where the operating temperatures are generally in the range of 250 to 350 F.

3.7A.3.1.1 Hot Precipitators. Hot precipitators have been used on low sulfur coals to take advantage of the lower resistivity of the fly ash at high temperatures. The improvement in the resistivity of the fly ash with higher temperatures for medium and high sulfur coals is not as significant as with low sulfur coals and not required for performance. Therefore, hot precipitators have not generally been applied when firing such fuels.

Some heat is lost from the flue gas even though heavy thermal insulation is utilized. Since this heat loss is ahead of the air heater, the thermal efficiency of the boiler is lowered. There have been some structural failures of hot precipitators due to thermal expansions and this problem could be compounded by numerous starts per year. Also, some hot side precipitators have experienced problems resulting in poor performance.

Although the hot precipitator theoretically requires a smaller collection area than a cold precipitator to achieve the required removal efficiency, a hot precipitator will have a greater volumetric flow rate than a cold precipitator because of its higher operating temperature. The higher volumetric flow rates tend to require larger precipitator casings, ducts, and flues as compared to the cold precipitator.

3.7A.3.1.2 Cold Precipitators. The lower flue gas temperature in a cold precipitator results in higher ash resistivity. The desired level of collection efficiency is obtained at the higher resistivity by increasing the precipitator SCA, the sectionalization, and the transformer-rectifier capacity. Cold precipitators have been used for many years on units burning low sulfur western fuels as well as higher sulfur eastern fuels.

The advantages of cold precipitators over hot precipitators are as follows.

(1) Cold precipitators are located downstream of the air heaters, and any heat loss from a cold precipitator does not affect the boiler efficiency.

(2) Cold precipitators are subjected to less thermal expansion and stress, because of its lower operating temperature.

The fuels under consideration are not expected to have exceptionally high resistivity or other properties which would make the ash difficult to collect at the temperatures expected following the air heater. Therefore, it is not necessary to consider a hot side precipitator with its inherent expansion and design problems. Only cold side precipitators will be considered for use at this station.

Design parameters for cold precipitators are shown on Table 3.7A-2. These parameters have been developed in this analysis for cost comparisons.

3.7A.3.2 Fabric Filters

Fabric filters have been extensively used for years in small industrial applications but, until recently, have not been used extensively in utility boiler applications. This was primarily due to short bag life rather than to the inability of this type of device to collect particulates. Recently, however, a large amount of work has been performed by fabric filter manufacturers, electric utilities, and textile manufacturers to determine how to correct the most common causes of bag failure and to develop more durable fabrics. As a consequence, fabric filters are becoming more prevalent in the utility market, especially for small and medium size units.

Fabric filters utilize fabric bags as filters to collect the particulate. The process of filtration of gases to remove particulate matter is a combination of the mechanisms of inertial impaction, interception, and diffusion. Factors such as gravitational, electrostatic, or thermal forces can have an influence on the collection efficiency.

The particulate-laden gas enters the fabric filter compartments and passes through the filter bags. The collected particulate forms a cake on the bags which enhances the filtering efficiency. At predetermined time intervals or on a high differential pressure signal, the bags are cleaned of most of the collected particulate by reverse air-deflation, shaking, or a rapid pulse of air, leaving a residual dust layer on the bags to aid in the filtration process. The particulates are collected in hoppers below the fabric filter housing and are periodically removed from the hoppers by conventional fly ash removal systems.

Generally, filter bag life depends on the duty load of the fabric filter, the cleaning cycle frequency, and the care in handling the filter bag by service or maintenance personnel. The filter bags which are used in a utility boiler application are generally fiberglass with a Teflon or silicone-graphite finish. These filter bags have a maximum operating temperature of approximately 550 F and are resistant to acid or alkali attack.

The flue gas is not allowed to cool to the acid or water dew point in the fabric filter. Severe corrosion damage to the fabric filter's structural steel can occur if flue gas temperature is not properly controlled. Whenever a fabric filter compartment is taken off-line for maintenance or the generating unit is shut down for an extended period, the fabric filter must be thoroughly ventilated to prevent condensation and corrosion as the filter cools.

Fiberglass bag material is susceptible to failure through abrasion and breakage of the glass fibers during the bag cleaning cycle. For this reason reverse air-deflation cleaning is most often specified with this bag material as it exposes the bags to the least stress. In instances where reverse air has proven insufficient to adequately clean the bags, shaking of the bags during cleaning has been included.

Fabric filter collection efficiencies are not affected by the resistivity of the fly ash, so the filters are sized only on the flue gas flow rate and the design air-to-cloth ratio. The selection of the air-to-cloth ratio for woven glass bag filters is a function of the desired bag life, residual pressure drop, method of cleaning, and required cleaning cycle. An air-to-cloth ratio of 2:1 is typical for a reverse air type fabric filter used in utility applications.

Design parameters for a fabric filter system for any of the three coals are listed on Table 3.7A-3. These parameters were used in the economic analyses.

3.7A.3.3 Wet Particulate Scrubbers

Wet particulate scrubbers have been utilized on coal-fired power plants. The wet particulate scrubber is normally utilized in the power industry in combination with a sulfur dioxide removal scrubber. Particulate scrubbers have not demonstrated a capability for providing continuous compliance with an emission standard of 0.03 lb/MBtu. New developments which utilize a low energy venturi, spray tower and a wet electrostatic precipitator at the scrubber outlet as a "polishing" device have been pilot tested but have not been demonstrated on a large unit. Wet particulate scrubbers, including those with wet electrostatic precipitators, have not demonstrated the capability for continuous compliance with particulate emission standards and are not considered further.

3.7A.4 COMPARATIVE COSTS OF VIABLE PARTICULATE REMOVAL SYSTEM

Comparative capital and operating costs for the viable alternative methods of particulate removal have been estimated based on the design parameters presented on Tables 3.7A-2 and 3.7A-3. These costs are presented in Table 3.7A-4 and are described below.

3.7A.4.1 Capital Costs

The estimated capital cost for each of the alternative methods of particulate removal is shown on Table 3.7A-4. These costs include the basic equipment and also the structural support steel, limited amounts of ductwork, and insulation and lagging. For the purpose of this study the foundations required for the equipment were considered to be equivalent for the different methods.

The electrostatic precipitator is complete with casings, transformer-rectifiers, inlet diffuser and outlet nozzle, a roof weather enclosure, system controls, access platforms, and rapping system. Also included is electrical construction.

Fabric filters include casings complete with fabric filter bags, dampers with operators, system controls, access platforms, and reverse air fans with electric drive motors. Electrical construction is also included.

Escalation to 1985 which is the estimated time of delivery, Sales Tax and interest during construction based on a two year erection period have been added for comparative purposes. Indirect costs include company overheads and engineering costs and have been added.

3.7A.4.2 Operating Costs

The estimated levelized annual operating cost for each of the alternative methods of particulate removal is shown on Table 3.7A-4. These operating costs include demand and energy charges for auxiliary power consumption including differential induced draft fan power. The operation and maintenance costs for each alternative based on personnel requirements are also included. Fabric filter bag replacement is included under maintenance and is based on an average 2 year bag life.

3.7A.4.3 Summary of Costs

Comparison of the annual costs presented on Table 3.7A-4 indicates that a cold side electrostatic precipitator has the lowest capital cost, the lowest annual operating cost, and the lowest total annual cost of the methods investigated for particulate removal.

3.7A.5 CONCLUSIONS

A cold side electrostatic precipitator is the most advantageous combustion gas particulate removal system for Stanton Energy Center Unit 1. An evaluation of available systems and costs (Table 3.7A-4) indicates that this is the most reliable and economical particulate removal system. In addition, it has the most operating experience. Electrostatic precipitators have been used on utility boilers the size of Stanton Energy Center Unit 1 for many years. Also, the reliability of cold side precipitators on medium and high sulfur fuels has been demonstrated.

The precipitator will be designed to meet NSPS when collecting ash from a low sulfur Appalachian coal flue gas. The ash in this coal flue gas will be hard to collect, resulting in a large precipitator. If coals with lower ash resistivity are burned, the collection efficiency will increase, resulting in emission rates less than NSPS.

TABLE 3.7A-1. PARTICULATE PRODUCTION RATES AND REMOVAL REQUIREMENTS

Parameter	Illinois Coal Maximum	Illinois Coal Average	Medium Sulfur Appalachian Coal Maximum	Medium Sulfur Appalachian Coal Average	High Sulfur Appalachian Coal Maximum	High Sulfur Appalachian Coal Average
Fly ash production rate, pounds per 10^6 Btu	10.67	6.14	8.00	3.96	9.19	3.74
Allowable particulate emission, pounds per 10^6 Btu	0.03	0.03	0.03	0.03	0.03	0.03
Particulate removal rate, pounds per 10^6 Btu	10.64	6.11	7.97	3.93	9.16	3.71
Particulate removal efficiency, per cent	99.7	99.5	99.6	99.2	99.7	99.2

TABLE 3.7A-2. ELECTROSTATIC PRECIPITATOR DESIGN PARAMETERS*

Parameter	Coal: Illinois	Coal: Medium Sulfur Appalachian	Coal: Higher Sulfur Appalachian
Removal efficiency, per cent	99.7	99.6	99.7
Gas flow, acfm	1,814,000	1,768,000	1,860,000
Gas temperature, F	300	300	300
Gas velocity, fps	4	4	4
Effective front end area, ft^2	7,560	7,370	7,750
Plate height, ft	36	42	41
Effective width, ft	210	175	189
Field depth, ft	72	84	82
Aspect ratio	2.0	2.0	2.0
Specific collecting area, ft^2/Macfm	600	700	675
Total collecting area, ft^2	1,088,000	1,238,000	1,256,000
Number of transformer recti fiers	48	60	60
Total power required, MW	2.7	3.1	3.2

*Design parameters used for capital and operating cost development and are for one 460 MW gross unit.

TABLE 3.7A-3. FABRIC FILTER DESIGN PARAMETERS*

Parameter	Value
Gas flow, acfm	1,860,000
Gas temperature, F	300
Number of units	2
Number of compartments	32
Number of bags per compartment	320
Total number of bags	10,240
Filter area per bag, ft^2	90
Filter area per compartment, ft^2	28,800
Total filter area, ft^2	921,600
Air-to-cloth ratio, $ft^3/min/ft^2$	
All compartments	2.02:1
1 compartment cleaning	2.15:1
1 compartment cleaning, 1 compartment maintenance	2.31:1
Bag cleaning method	Reverse Air
Normal operation flue gas, $\Delta\rho$	4 to 6

*Design parameters used in capital and operating cost developments and are for one 460 MW gross unit.

TABLE 3.7A-4. COMPARATIVE COSTS FOR PARTICULATE REMOVAL EQUIPMENT*

	Electrostatic Precipitator			
	Illinois Coal $1,000	Medium Sulfur Appalachian Coal $1,000	High Sulfur Appalachian Coal $1,000	Fabric Filter $1,000
Capital Costs				
Material and erection (1980 costs)	Base	1,530	1,711	5,924
Escalation	Base	718	803	2,780
Sales tax	Base	90	101	348
Interest during construction	Base	142	159	551
Indirect cost	Base	446	499	1,728
Differential capital cost	Base	2,926	3,273	11,331
Levelized Operating Costs				
Operating personnel	Base	Base	Base	Base
Maintenance**	Base	Base	Base	715
Demand charge***	59	112	119	Base
Energy charge***	Base	86	96	434
Comparative operating cost	59	198	215	1,149
Differential operating cost	Base	139	156	1,090
Annual Costs				
Fixed charges	Base	298	334	1,156
Levelized operating costs	Base	139	156	1,090
Comparative annual costs	Base	437	490	2,246

*Costs are presented for one 460 MW gross unit.

**Maintenance includes bag replacement.

***Includes differential ID fan power requirements.

APPENDIX 3.7B

ANALYSIS OF DESULFURIZATION SYSTEMS

APPENDIX 3.7B
ANALYSIS OF DESULFURIZATION SYSTEMS

3.7B.1 INTRODUCTION

This appendix discusses the available methods of desulfurization considered for Stanton Energy Center Unit 1 and their feasibility for use on the project.

3.7B.2 REQUIREMENTS OF DESULFURIZATION SYSTEM

(1) The desulfurization system shall be capable of operation in accordance with the requirements outlined in Florida Ambient Air Standards and New Source Performance Standards (NSPS). The emission requirements in NSPS are more restrictive than the Florida Ambient Air standards and therefore shall prevail. The NSPS standards are as follows.

(a) The sulfur dioxide (SO_2) emission rate will be limited to a maximum of 1.2 pounds SO_2 per 10^6 Btu heat input.

(b) A percentage reduction in sulfur dioxide emissions from the sulfur contained in the raw coal must be achieved. A curve depicting the allowable emission rates of SO_2 emitted versus the sulfur content of the coal is shown in Figure 3.7B-1. This reduction must be at least 70 per cent (30 day average) and the emission rate must not exceed 0.60 pound SO_2 per 10^6 Btu heat input unless at least a 90 per cent reduction is achieved. Compliance with these requirements will be determined on the basis of a 30-day rolling average. Percentage removal credit can be obtained for coal preparation and reduction.

(c) Gas bypassing is allowed if the criteria in (b) are met.

The production rates and removal requirements of sulfur dioxide for the three coals considered are listed in Table 3.7B-1.

(2) The operating reliability of the desulfurization system shall be such that the generating capability of the unit shall not be limited by the desulfurization system.

(3) The desulfurization system shall meet the following requirements.

(a) Demonstrated feasibility.

(b) Advanced level of availability.

(c) Acceptance by utility industry.

(d) Favorable economic impact.

(e) Acceptable environmental impact of waste disposal or a marketable end product.

(f) Applicability to any two of the coals under consideration.

3.7B.3 ALTERNATE DESULFURIZATION SYSTEMS

3.7B.3.1 Desulfurization Methods

An enormous amount of research, testing, and development has occurred in the area of flue gas desulfurization in the past 10 years. In the United States alone, operating units with nearly 24,000 megawatts of electric generating capacity are currently equipped with FGD systems. An additional 27,000 megawatts of generating capacity are planned or under construction with flue gas desulfurization. Of the over 200 desulfurization processes that have been studied, the following seven processes have been sold for application to a utility steam generator.

(1) Lime.

(2) Limestone.

(3) Spray absorber processes.

(4) Double alkali.

(5) Soda ash.

(6) Magnesium oxide.

(7) Wellman-Lord.

One other process, flue gas sparging (Chiyoda), is being offered but has not yet been utilized in a full scale utility application. Table 3.7B-2 presents a summary of the current status of desulfurization systems on utility steam generator installations in the United States.

The leading type of desulfurization processes for large power plants are identified in the block diagram shown on Figure 3.7B-2. The basic divisions are into recovery and throwaway processes based on the treatment approach for the scrubber solids, with subdivisions into wet and dry processes.

In throwaway processes the end product has no significant commercial value and must be disposed of in ponds or landfills. Recovery processes yield a salable materials such as gypsum, sulfur, sulfuric acid, or fertilizer base compounds. Extensive research is presently underway for development of scrubbing processes which would yield either a salable end product or a product which is easily and economically disposed.

3.7B.3.1.1 Throwaway Processes

(1) Lime Process. Lime (CaO) is slaked to calcium hydroxide and used to absorb the sulfur dioxide from the flue gas producing a wet sludge. A schematic of the system is shown on Figure 3.7B-3. The scrubber additive system requires a slaker to hydrate the lime. The scrubber vessels are generally open, counter-current spray tower types with multiple spray levels. SO_2 removal efficiencies of about 90 per cent are achievable. The use of packed towers or mobile bed towers can further improve efficiencies. Liquid to gas (L/G) ratios of 40 to 60 gallons per 1,000 cubic feet of gas are typical for lime scrubbers. There is considerable operating experience and a high degree of reliability for most operational systems. The lime additive is generally available; however, it is expensive, approximately 10 times the cost of limestone on a per ton basis. The system is generally controlled by monitoring the pH in the recirculating liquor. The required pH level is established by the SO_2 removal required. System controls are responsive because of the rapid disolution of the slaked lime.

The major disadvantage of the lime scrubber is that the sludge produced generally contains a significant amount of calcium sulfite which does not dewater readily and is also thixotropic.

The thixotropic property results in a sludge which, when moved, tends to reliquify. Forced oxidation, to decrease the sulfite and increase the sulfate concentration, is difficult with a lime scrubber because the normal pH operating range (6 to 7) is not favorable to oxidation.

(2) Limestone Process. The limestone process, which is also shown on Figure 3.7B-3, is very similar to the lime process. The basic difference is that limestone ($CaCO_3$) is crushed, slurried and used as the alkali additive. The additive system utilizes a ball mill for grinding and slurrying the limestone. The scrubber vessels are generally open, counter-current spray towers with multiple spray levels. SO_2 removal efficiencies up to 90 per cent are achievable. The use of packed towers or mobile bed towers to increase liquid surface areas can result in efficiencies up to 95 per cent. Liquid to gas ratios of 50 to 80 gallons per 1,000 cubic feet of gas treated are typical. The utility industry has considerable operating experience with limestone scrubbers and there is a high degree of reliability for most operational systems. Limestone additive is generally inexpensive and readily available. The system is generally controlled at a selected pH in the recirculating liquor, which is necessary to remove SO_2 and dissolve the limestone. The pH control point in a limestone scrubber is generally lower than for a lime scrubber. The system controls are not as responsive as a lime system because of the lower reactivity of the limestone and it's inherent buffering tendencies. The system can utilize forced oxidation of the sludge from sulfite to sulfate which creates a sludge which is easily dewatered and disposable.

The disadvantages of the limestone scrubber include the maintenance requirements for the grinding equipment and for the piping and pumping systems because of the abrasiveness of the slurry. This process usually creates more sludge for disposal than other systems because of the lower utilization of the additive.

(3) Spray Absorber Process. The spray absorber process is a relatively recent development in combustion gas cleaning technology. It is a two-stage sulfur dioxide and particulate removal process that utilizes a spray dryer type absorber and fabric filter or electrostatic precipitator in series. Both lime and soda ash can be used as additives. The stoichiometric quantities of lime required are greater than the quantities of soda ash due to the lower reactivity of lime. SO_2 removal with lime is limited to a maximum of about 90 per cent.

A spray absorber is a type of continuous mass transfer equipment. As shown on Figure 3.7B-4 lime slurry or soda ash solution is pumped to an atomizer, located at the top of the spray dryer, which produces a dispersed spray of fine droplets. The alkali absorbent is accelerated to a high velocity in the high speed rotating atomizer and is forced radially outward in a cross-flow path to the incoming flue gas. Flue gas from the air heater enters the spray dryer where it passes downward through the atomized alkali solution.

The turbulent characteristic of the combustion gas within the absorber and the atomized alkali droplets provide intimate mixing of the two phases. The alkali additive reacts with the gas which is absorbed by the water to form sulfite and sulfate. At the same time, the thermal energy of the combustion gas evaporates the water in the droplets to produce a dry mixture of sulfite, sulfate, and unreacted alkali additive. These dry waste products are removed along with the fly ash in the second stage of the system consisting of a fabric filter or electrostatic precipitator. In this stage, additional sulfur dioxide removal can occur due to reaction with unreacted alkali additive material. The spent absorbent can either be conveyed to a recirculation system or to landfill for disposal.

The typical liquid-to-gas ratio for the spray absorber is approximately 0.3 gallon per 1,000 acf of the combustion gas treated. Because of the low liquid-to-gas ratio, there is not enough water injected to cool the gas to its dew point, and reheating is not required; however, the combustion gas temperature is cooled to within 20-50 F of the water dew point in the spray absorber.

Control of the spray absorber is accomplished by measuring the temperature of the combustion gas at the outlet of the spray absorber and the sulfur dioxide content in the combustion gas entering the chimney. The amount of dilution water added to the additive solution prior to atomization in the spray absorber is controlled by the outlet combustion gas temperature. The solids per cent of the additive slurry entering the spray absorber is controlled by outlet sulfur dioxide concentration.

The 100 MW lime additive full scale demonstration unit, a Northern States Power Riverside plant, has recently started operation. No data has been made available, but preliminary reports indicate that aside from the usual problems of a new system, the demonstration plant is performing as expected. A 100 MW demonstration plant at Niagara Mohawk Power Cooperative's Charles Huntley station is currently under construction and is scheduled for initial testing in 1982. This system will use sodium carbonate as an additive. Lime additive spray absorber systems for a 455 MW unit at Basin Electric Power Cooperative's Antelope Valley Plant and a 550 MW unit at their Laramie River Plant are scheduled to start up full scale in late 1981 and 1982. A 400 MW unit at Otter Tail Power's Coyote Station is scheduled to start up with soda ash additive in 1981.

(4) Double-Alkali Process. This concept uses a counterflow spray tower type scrubber with soda ash as the alkali additive. The soda ash can then be regenerated by the addition of lime in a secondary reactor. A process schematic is shown on Figure 3.7B-5. There is limited utility experience with operational systems. The system has demonstrated acceptable reliability and SO_2 removal performance.

The advantages of the system are that the scrubber liquor is a clear solution rather than a slurry so that the potential for wear and plugging in the scrubber loop are minimized. The system has a high inherent SO_2 removal efficiency because of the reactivity of the sodium in the scrubber loop. Removal efficiencies of 95 per cent and greater are common with L/G ratios of 10 to 40 gallons per 1,000 cubic feet of gas treated. The disadvantages includes the need for two alkali preparation systems, one for the soda ash and another for the lime. The regeneration of the sodium by the lime requires careful operator attention in that portion of the process. A major drawback is that sodium recovery in the full scale units has not been as high as originally planned which has significantly increased the use of an expensive additive. The sludge from the double-alkali process can contain significant amounts of sodium sulfate and sulfite. This makes the sludge difficult to dispose of because of leaching and mechanical instability.

(5) Soda Ash Process. The soda ash process as shown on Figure 3.7B-6 is very similar to the double-alkali process except that lime is not added to the process and the sodium is not recovered for reuse in the scrubber. The scrubber liquor is pumped directly from the recirculation tank to a disposal area. This process requires the use of evaporation ponds for disposal of the waste. This process has only been applied in the arid areas of the U.S. where there is the possibility of using an evaporation pond.

(6) Flue Gas Sparging (Chiyoda) Process. As shown on Figure 3.7B-7, the flue gas leaving the induced draft fans is first quenched by spray nozzles to control the gas temperature and the wet/dry interface of the system. The gas then enters the reactor where it is directed downward to numerous sparging pipes. These pipes are partially submerged in the absorber slurry. The gas, leaving the sparging pipes as finely divided bubbles, reacts with the limestone in the slurry to form calcium sulfite and calcium

sulfate. The treated flue gas leaves the reactor and passes through the mist eliminator. The oxidizing air blower provides the air for oxidizing the sulfite to sulfate in the reactor. The absorber slurry continuously overflows by gravity to the limestone slurry tank where fresh limestone additive is introduced. Limestone addition is controlled by the pH of the reaction tank slurry. A portion of the absorber slurry is discharged to the solids disposal system by the reactor blowdown pumps. Reclaimed water from the solids disposal system is returned to limestone slurry tank and the flue gas quench sprays.

A 23 MW demonstration plant at Gulf Power's Scholz Station has completed over a year of operating data from treating flue gas from a boiler burning Alabama bituminous coal. There are no full scale systems operating or under contract. A full scale demonstration unit is presently being sought by EPRI.

3.7B.3.1.2 Recovery Processes. The recovery processes utilize a spray tower type scrubber similar to that utilized in the lime or limestone system.

(1) Magnesium Oxide Process. Magnesium oxide (MgO), in a liquor, is used to absorb sulfur dioxide in this process and magnesium sulfite ($MgSO_3$) is produced as an intermediate product. Sulfur dioxide is extracted from this sulfite and converted to sulfuric acid. The magnesium sulfite salt may be shipped to an offsite sulfuric acid plant, which returns the reformed MgO for reuse in the scrubber. MgO recovery has not been as efficient as originally planned. This increases the requirement for an expensive additive. There is also a requirement for a sulfuric acid plant within a reasonable distance of the plant site for additive recovery.

Philadelphia Electric has been testing the magnesium oxide system since 1975 at its Eddystone station and has awarded contracts for this system for three more units (724 MW total). The expected startup date for these systems is 1982.

(2) Wellman-Lord Process. In this process, sodium sulfite (Na_2SO_3) is used to absorb the sulfur dioxide and elemental sulfur or SO_2 can be ultimately produced. The process requires that a complex recovery process be operated as part of the scrubber system. This recovery procss would depend on the ultimate form for the sulfur. Soda ash additive is required for the process and there is a requirement to dispose of sodium sulfate sludge. There is also a need for a market or disposal method for the concentrated SO_2 or sulfur produced.

The first full scale Wellman-Lord FGD system was installed at Public Service of New Mexico's San Juan Generating Station in early 1978. The operating experience has been good with the unit exhibiting acceptable availability.

3.7B.3.2 Feasible Desulfurization Systems

To be considered as a feasible alternative for flue gas desulfurization for the Stanton project, a process must meet the criteria presented in Section 3.7B.2.

The lime and limestone processes meet all the requirements for a feasible system. The utility industry has to date used these two processes extensively. Both lime and limestone are available in the counties surrounding the site. Limestone is mined locally. Lime, which is produced by calcining limestone, is available by rail from various in-state and out-of-state producers.

The spray absorber process has been pilot tested, and sold to the utility industry. There are several suppliers of the process. The process has not been demonstrated on a full scale unit and has therefore not demonstrated an advanced level of availability. The process has been generally accepted by the utility industry. However, the dry scrubbing process will not be applicable to all the coals under consideration. The amount of additive required for continuous high efficiency removal when coupled with the need to keep the flue gas temperature above the water dew point results in technical limitations (pumping problems) for the high removal efficiencies required. The spray absorber process is judged not feasible for use on this project.

The double alkali process offers certain operational advantages, such as scrubbing with a clear solution rather than a slurry. The process has been successfully applied and has demonstrated acceptable reliability. The process will use nearly the same amount of lime as a lime scrubber. The process also requires the use of soda ash to make up for sodium losses in the sludge. The soda ash usage requirement is higher than the differential lime usage and soda ash is significantly more expensive than lime. The sludge produced contains sodium and is not easily disposed in an environmentally acceptable fashion. The double alkali process will not be economically attractive because of the soda ash usage and the cost for sludge disposal and is therefore not considered feasible for this project.

The soda ash process is not considered feasible for this project for the same reasons that the double alkali system is not considered feasible.

The flue gas sparging process has not been applied on a full scale unit. This process has not demonstrated the ability for continuous acceptable performance with an acceptable availability. This process is not considered feasible for use on this project.

The magnesium oxide process has not been widely accepted by the utility industry. There are no full scale units presently using this process for SO_2 removal. The recovery rate for the magnesium oxide has not been as good as originally planned based on the pilot work. This process requires a sulfuric acid plant for magnesium recovery at a location relatively near the plant. This process is not considered feasible for use on this project.

The Wellman-Lord process has not been widely accepted by the utility industry. The additive required is soda ash which would be expensive. This process requires a rather complex sodium recovery process which must be located and operated on site. This process also requires a market or at least an acceptable disposal method for the sodium sulfate and liquid or gaseous SO_2 which will be produced. These products are not easily stored on site in large quantities. The lack of an acceptable disposal method for the wastes produced makes this process not feasible for use on this project.

In summary, the lime and limestone processes are the only processes considered to be feasible with all of the potential coals.

3.7B.4 COMPARATIVE COSTS

3.7B.4.1 Capital Costs

The estimated capital cost for each of the alternative methods for SO_2 removal is shown on Table 3.7B-3. These costs include the basic equipment and also the structural support steel, interconnecting ductwork, and insulation and lagging. For the purpose of this study, the foundations required for the equipment were considered to be equivalent for the different methods. Capital costs for the additive preparation system have been included based on the cost of the additive receiving and yard facilities as well as the slurry preparation equipment and tanks. Capital costs have also been included for solids disposal based on a commercial system for mixing the scrubber sludge with fly ash. No optimization of the disposal system has been included.

3.7B.4.2 Operating Costs

The estimated levelized annual operating costs for each of the alternative methods for SO_2 removal is shown on Table 3.7B-3. These operating costs include demand and energy charges for auxiliary power including induced draft fan power. The additive cost has been included based on the expected additive usage of each process and the delivered additive prices quoted by suppliers.

3.7B.4.3 Summary of Costs

The comparative annual costs are shown on Table 3.7B-3. These costs include the fixed charges on capital expenditures and the levelized operating costs. A comparison of the annual costs for the wet scrubbers indicates that the limestone scrubber has a higher capital cost, lower annual operating cost and lower total annual cost for the three coals considered in this study.

3.7B.5 CONCLUSIONS

A wet limestone scrubber is the most advantageous combustion gas desulfurization system for Stanton Energy Center Unit 1. An evaluation of available desulfurization system costs (Table 3.7B-3) indicates that this is the most reliable and economical desulfurization system. In addition, it has extensive operating experience. Wet limestone scrubbers have been used on utility boilers for many years and have a demonstrated reliability.

TABLE 3.7B-1. SULFUR DIOXIDE PRODUCTION RATES AND REMOVAL REQUIREMENTS

Parameter	Illinois Coal Maximum	Illinois Coal Average	Medium Sulfur Appalachian Coal Maximum	Medium Sulfur Appalachian Coal Average	Higher Sulfur Appalachian Coal Maximum	Higher Sulfur Appalachian Coal Average
SO_2 production from raw coal, pounds per 10^6 Btu (100 per cent conversion of sulfur to sulfur dioxide)	12.24	5.11	2.50	1.31	4.09	2.18
Overall SO_2 removal requirements to meet allowable emission rate (based on raw coal), per cent	91	89	76	70	86	73
Allowable SO_2 emission rate (based on raw coal), pounds per 10^6 Btu	1.20	0.60	0.60	0.39	0.60	0.60
Required SO_2 reduction, pounds per 10^6 Btu	11.04	4.51	1.90	0.92	3.49	1.58
Sulfur reduction resulting from coal washing, pounds per 10^6 Btu (as SO_2)	3.67*	1.53*	--	--	--	--
SO_2 reduction required in FGD system, pounds per 10^6 Btu	7.37	2.98	1.90	0.92	3.49	1.58
FGD system removal efficiency, per cent	86**	84**	76	70	86	73

*The SO_2 reduction resulting from coal washing represents the difference in the SO_2 production estimated for the raw coal and the SO_2 production based on the Illinois washed coal analysis.

**FGD system removal efficiency is determined as the SO_2 reduction required for the washed Illinois coal to comply with the total reduction required for the raw coal.

TABLE 3.7B-2. STATUS OF GAS DESULFURIZATION PROCESSES ON COAL-FIRED STEAM ELECTRIC GENERATING UNITS IN THE UNITED STATES

	Throwaway Processes					Recovery Process		
Scrubber Status	Lime	Limestone	Spray Absorber	Soda Ash	Double-Alkali	Magnesium Oxide	Wellman-Lord	Total
Operational								
MW	8,801	11,464	110	925	1,181	0	1,540	24,021
Per cent of total	36	48	1	4	5	0	6	100
Under construction or contracts awarded								
MW	3,836	17,390	3,313	330	842	724	534	26,969
Per cent of total	14	65	12	1	3	3	2	100
								50,990 MW

Reference: EPA Utility FGD Survey: Arpil-June 1980, USEPA, EPA-600/7-81-012a, January 1981.

TABLE 3.7B-3. COMPARATIVE COSTS FOR DESULFURIZATION EQUIPMENT*

	Illinois Coal		Medium Sulfur Appalachian Coal		High Sulfur Appalachian Coal	
	Limestone $1,000	Lime $1,000	Limestone $1,000	Lime $1,000	Limestone $1,000	Lime $1,000
Capital Costs						
Scrubber material and erection	1,370	400	900	Base	1,840	900
Additive equipment	1,620	2,590	450	Base	1,110	760
Waste handling equipment	820	750	20	Base	250	180
Subtotal	3,810	3,790	1,370	Base	3,200	1,840
Escalation	1,790	1,780	640	Base	1,500	860
Escalated Cost	5,600	5,570	2,010	Base	4,700	2,700
Sales tax	220	220	80	Base	190	110
Interest during construction	390	390	140	Base	330	190
Indirect costs	700	690	250	Base	590	340
Comparative capital cost	6,910	6,870	2,480	Base	5,810	3,340
Levelized Operating Costs						
Demand charge	258	136	97	Base	229	126
Energy charge	693	404	222	Base	659	395
Additive	1,432	9,596	Base	2,007	391	3,953
Waste disposal	498	329	46	Base	139	60
Comparative operating costs	2,881	10,465	365	2,007	1,418	4,534
Differential operating costs	2,516	10,100	Base	1,642	1,053	4,169
Annual Costs						
Fixed charges	705	701	253	Base	593	341
Operating costs	2,516	10,100	Base	1,642	1,053	4,169
Comparative annual cost	3,221	10,801	253	1,642	1,646	4,510
Differential comparative annual cost	2,968	10,548	Base	1,389	1,393	4,257

*Costs are for one 460 MW gross unit.

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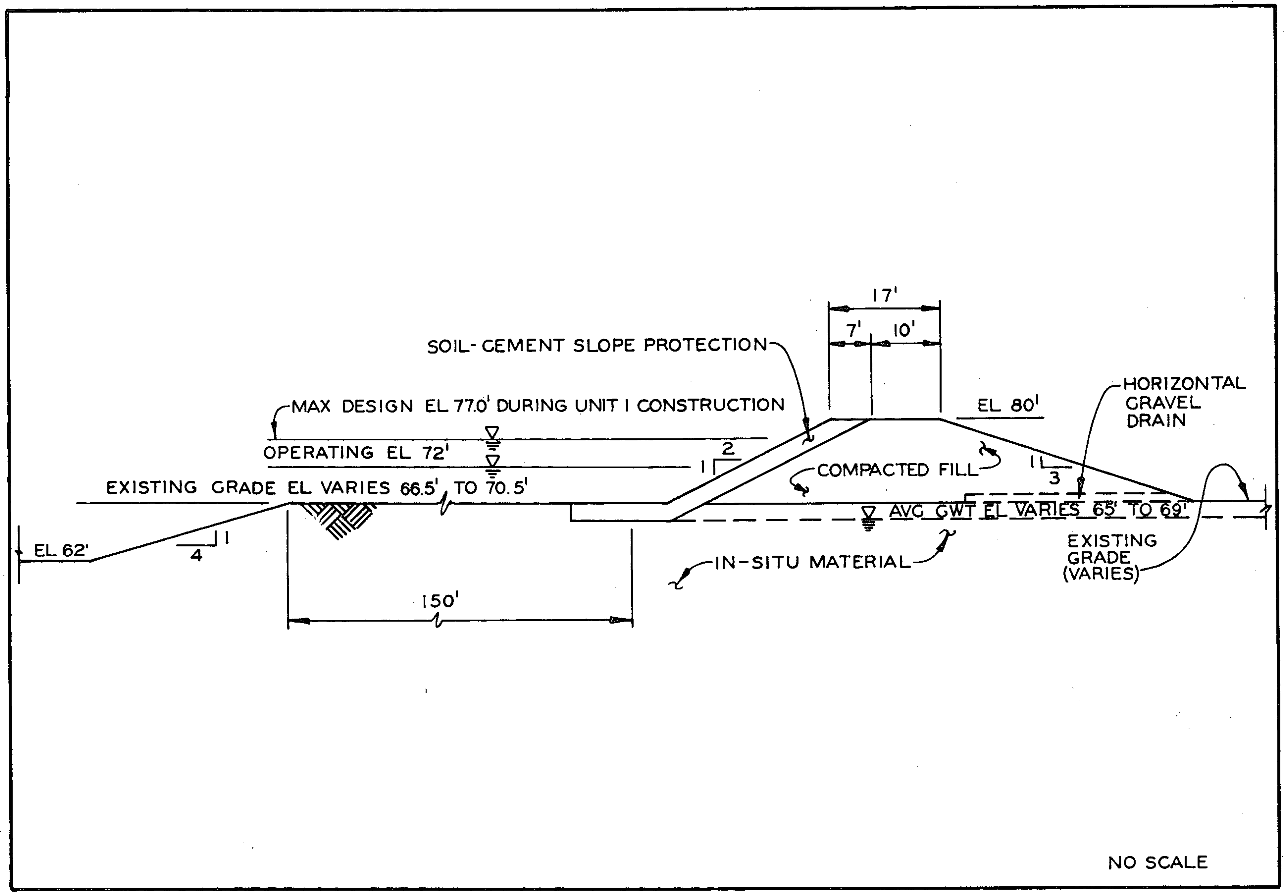

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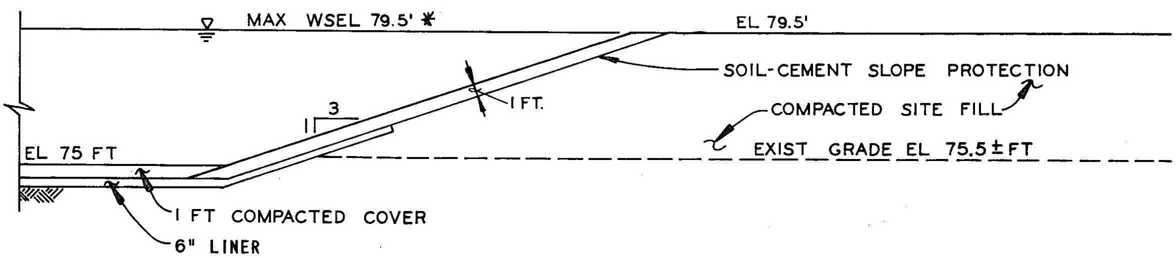
FIGURE 3.10-2. MAKEUP WATER SUPPLY STORAGE POND EMBANKMENT SECTION



*RESULTING FROM RUNOFF AND DIRECT PRECIPITATION FROM 100-YEAR, 24-HOUR EVENT

NO SCALE

5

FIGURE 3.10-3. COAL STORAGE AREA RUNOFF POND EMBANKMENT SECTION

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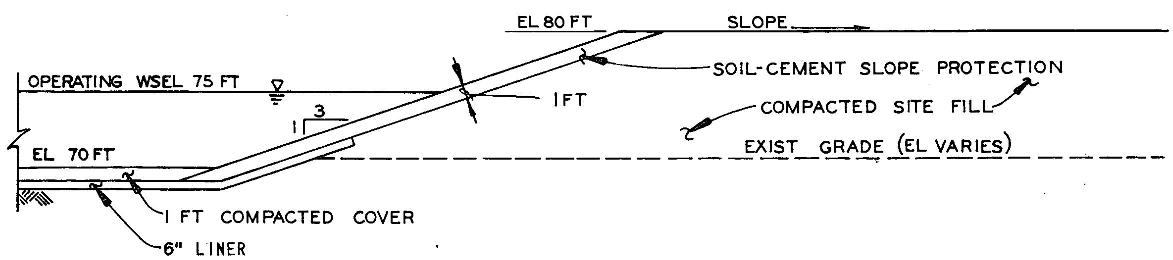

NO SCALE

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FIGURE 3.10-4. RECYCLE BASIN
EMBANKMENT SECTION

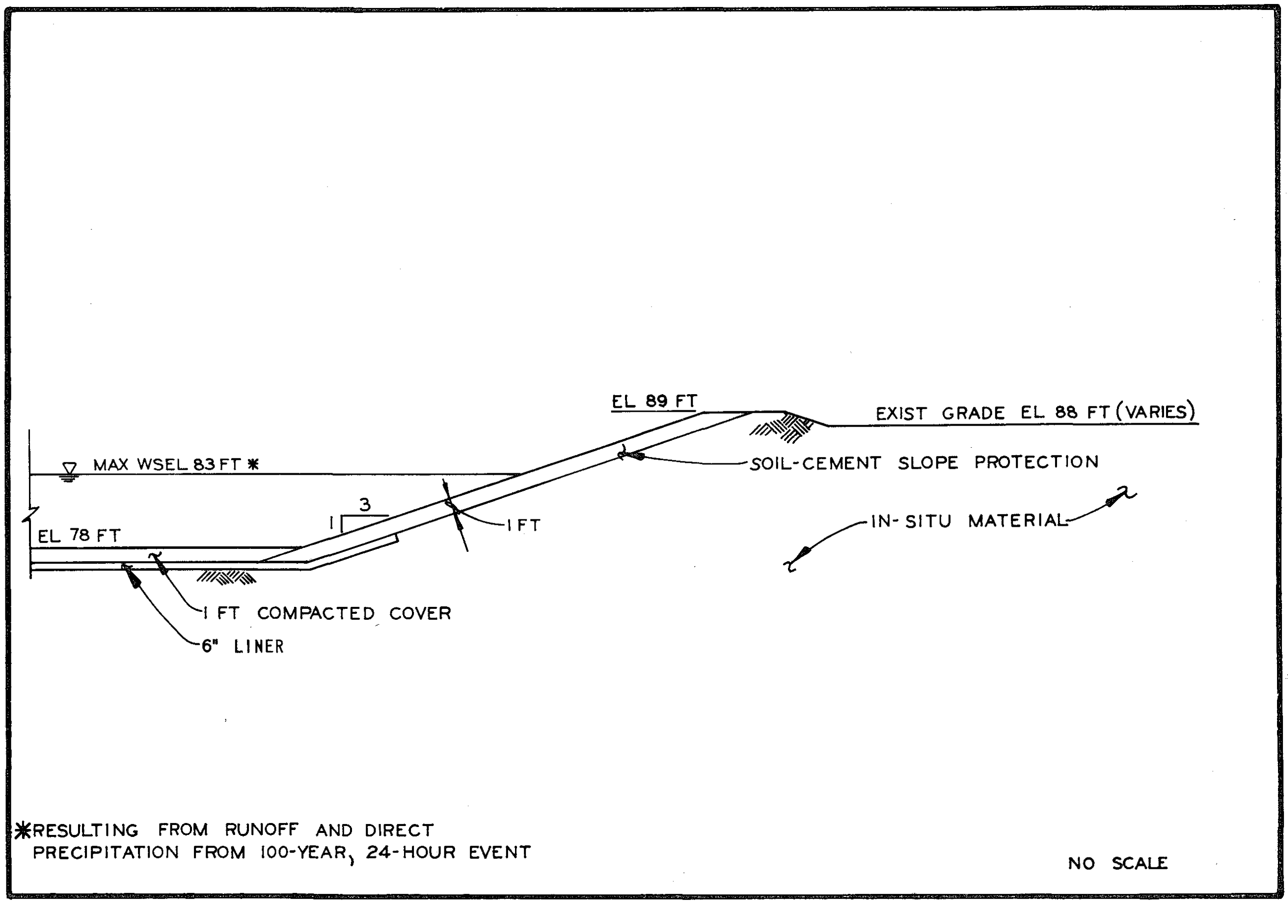

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FIGURE 3.10-5. ACTIVE COMBUSTION WASTE STORAGE AREA
RUNOFF POND EMBANKMENT SECTION

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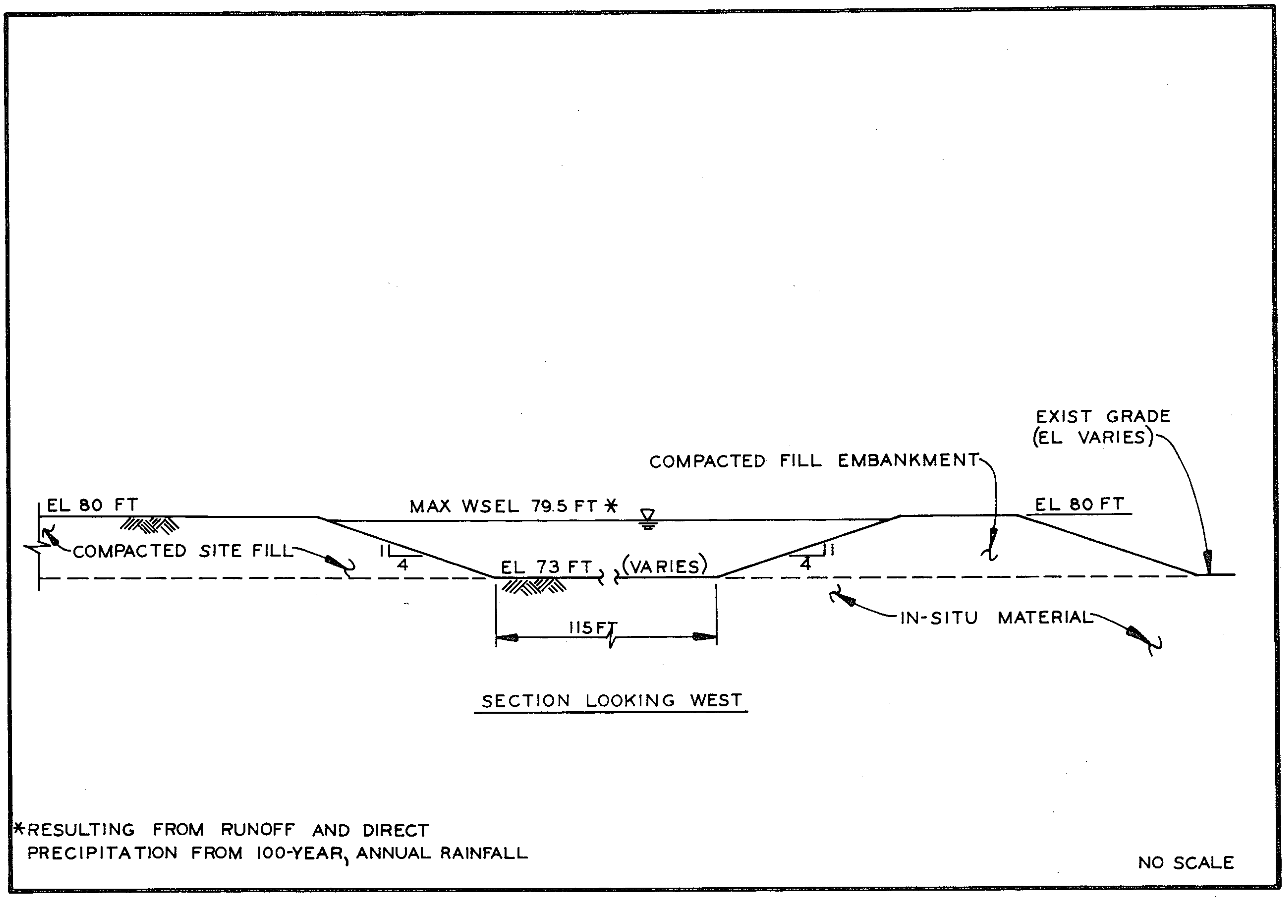

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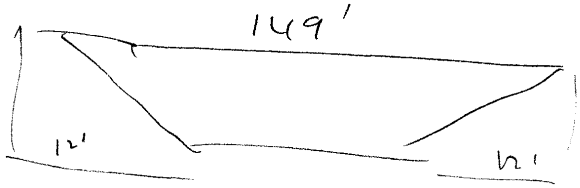
FIGURE 3.10-6. CONSTRUCTION LAYDOWN AREA RUNOFF RETENTION AREA SECTION

Old



$$A = \left(\frac{149 + 125}{2}\right)(4) = 548\,ft^2$$

New

$$\left[\frac{115 + (115 + 2(6.5 \times 4))}{2}\right] 6.5 = 916.5$$

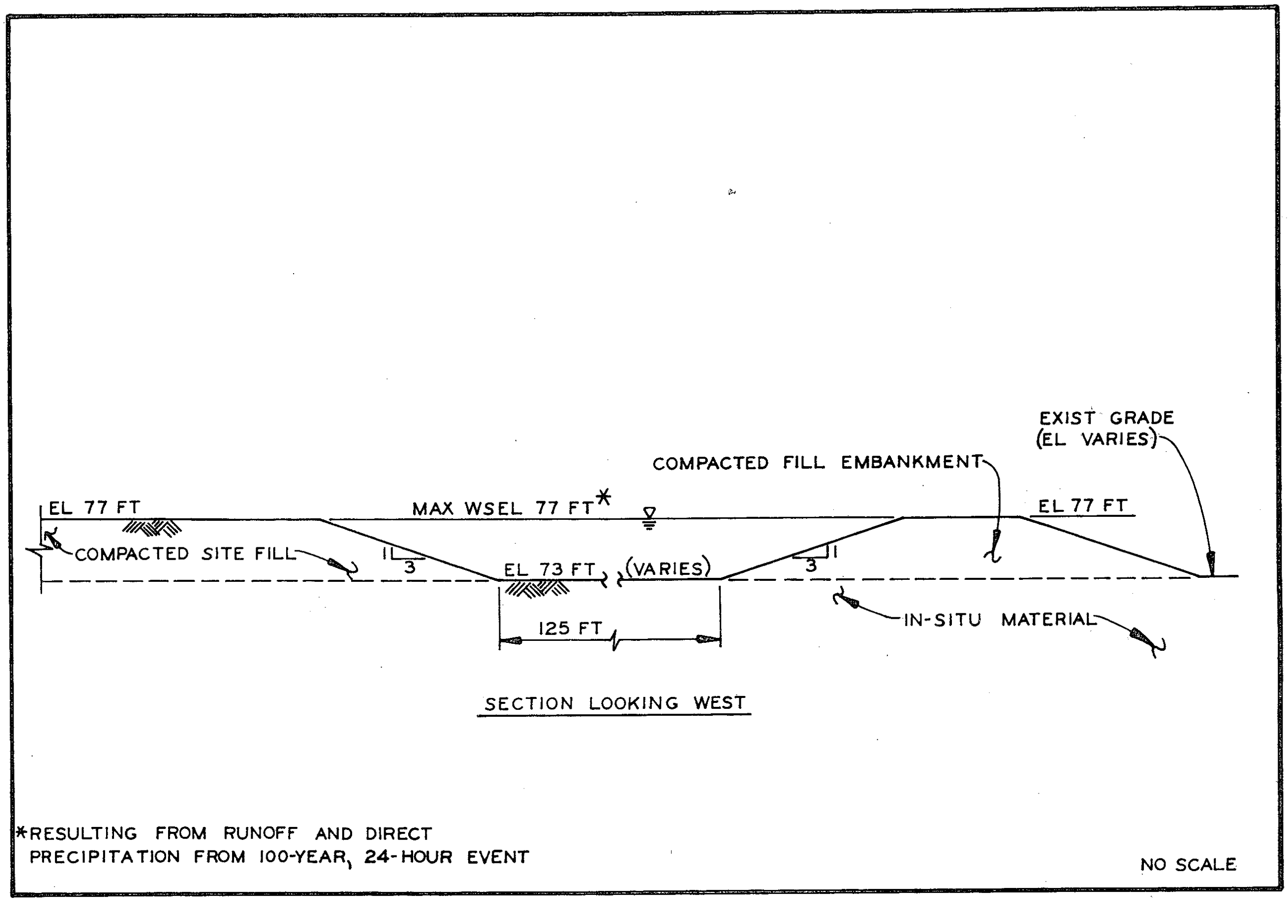


FIGURE 3.10-6. CONSTRUCTION LAYDOWN AREA RUNOFF RETENTION AREA SECTION

APPENDIX 3.10A
GENERAL SITE RUNOFF ANALYSIS

APPENDIX 3.10A
GENERAL SITE RUNOFF ANALYSIS

3.10A.1 Introduction

The objective of this appendix is to provide a detailed discussion of the procedures used to determine the general site area runoff characteristics and the operational characteristics of the makeup water supply storage pond. The capacity of the makeup water supply storage pond is determined by site runoff retention requirements during construction of Unit 1 as well as the estimated maximum makeup water requirement for one week with four units operating (560 acre-feet). After Unit 1 becomes 5
operational, a portion of the site runoff and direct pond precipitation will be utilized as cooling tower makeup.

3.10A.2 METEOROLOGY

There are no existing local meteorological data with long periods of record for the Stanton Energy Center site area. However, the Stanton Energy Center site is approximately 10 miles east-northeast of the Orlando International Airport. The average meteorological conditions for the airport are considered representative of the Stanton Energy Center site and are used to describe the local site meteorology. Evaporation records for the Lisbon weather station were assumed applicable for the site area.

3.10A.2.1 Precipitation. Total annual precipitation readings were analyzed through the utilization of plotting positions to determine total precipitation for periods of two and four successive years having a 25-year recur- 5
rence interval. Probability analysis based on plotting positions and a Log Pearson Type III distribution was performed on the total annual precipitation readings to determine the probability distribution of total annual precipitation. The derived precipitation data are given in Table 3.10A-1. The monthly distribution of annual precipitation has also been derived and is shown on Table 3.10A-2.

3.10A.2.2 Evaporation. The design of the makeup water supply storage pond is based on an average annual shallow lake evaporation of 47 inches. The monthly distribution of total annual evaporation is based on evaporation records available at the Lisbon station. The monthly distribution of the annual evaporation derived on the basis of 1960 monthly evaporation data is shown on Table 2.6-5.

3.10A.3 GENERAL SITE RUNOFF

In order to provide sufficient runoff retention capacity within the makeup water supply storage pond during Unit 1 construction, it is necessary to determine an appropriate value for the ratio of total annual surface runoff to total annual precipitation. This ratio will be denoted as the annual runoff ratio. The annual runoff ratio for the proposed site subsequent to the placement of compacted site fill material will vary from year to year, depending primarily on total annual precipitation and stage of site development.

Available gaging station records in the vicinity of the site, as well as technical publications, were examined to determine values of the annual runoff ratio for the existing site, prior to the commencement of earthwork operations. A discussion of this analysis is presented in Subsection 2.5.1.6. It was determined that approximately 10 inches of surface runoff would occur at the site in the existing condition during a year experiencing average total annual precipitation of about 51 inches. This represents an annual runoff ratio of 0.20. Table 3.10A-3 illustrates the dependence of the annual runoff ratio on precipitation by indicating values obtained at two gaging stations in the site vicinity for years experiencing variable amounts of precipitation. The annual runoff ratios given in Table 3.10A-3 are based on average annual streamflow and total annual precipitation. Runoff ratios computed in this manner can be exaggerated due to the contribution of ground water inflow to the measured discharge, expecially during years experiencing high total annual precipitation. The gaging station on the Econlockhatchee River near Chuluota is located approximately 10 miles upstream from the confluence with the St. Johns River. At this location, the Econlockhatchee River stream bed is well incised into the ground water table and receives a significant portion of its total discharge from ground water inflow. While the Little Econlockhatchee River near Union Park is not as deeply incised into the normal ground water table, a significant portion of the discharge would have resulted from ground water inflow during 1959 and 1960, both of which experienced above average amounts of precipitation. As a result, the annual runoff ratios based on direct surface runoff only for existing conditions would be somewhat less than those presented in Table 3.10A-3.

It is estimated that development of the Stanton Energy Center will require the placement of an average of 6 feet of compacted site fill to raise the project facilities above the 100-year flood elevation and provide adequate surface drainage. The placement of site fill material will provide additional soil moisture storage capability. The South Florida Water Management District (SFWMD) provides a method for determining soil moisture storage capability in a publication entitled Permit Information Manual, Volume IV, Management and Storage of Surface Waters. The SFWMD method for soil storage capability is based on depth to water table and per cent impervious area. The placement of site fill will increase the average depth to water table approximately 6 feet. It is assumed that 50 per cent of this area will be impervious. The application of the SFWMD method indicated that this fill will produce an additional 8 inches of compacted soil moisture storage capability. This additional soil moisture storage capability would tend to decrease the amount of total annual runoff experienced at the site subsequent to the placement of site fill. Table 3.10A-4 presents the existing annual runoff ratios (including base flow contribution) for the gaging station near Chuluota along with adjusted ratios computed by assuming that an additional 8 inches of annual precipitation infiltrated into the soil. It can be seen that the additional soil moisture storage capacity provided by the site fill significantly decreased the annual runoff ratios. Adjusted annual runoff ratios based on surface runoff only would be less than those given in Table 3.10A-4.

While it is assumed the placement of site fill material will provide additional soil moisture storage capacity, thereby decreasing the annual site runoff, it must also be noted that certain aspects of site development will tend to increase the amount of runoff experienced at the site. For example, the construction of an integrated grading and ditch system throughout the site will provide a more efficient means of drainage, thereby increasing annual runoff. In addition, the decrease in vegetative cover through the process of site development will cause a decrease in evapotranspiration losses and an increase in annual runoff.

Based on the above considerations, an annual runoff ratio of 0.20 will be used in the analysis of the makeup water supply storage pond for years experiencing average amounts of precipitation. An annual runoff ratio of 0.35 will be used for years experiencing significantly above average amounts of annual precipitation. It is felt that these coefficients represent
reasonable range of values to determine annual direct surface runoff from 5
the plant site.

3.10A.4 SEEPAGE

Embankment seepage analysis was performed through the use of a finite element computer program. The coefficients of permeability used were
derived from values applicable to similar soils within the region as well 5
as the results of a detailed onsite soils investigation program. The relationship between seepage and water surface elevation within the makeup water supply storage pond was determined from computer generated calculations performed for two headwater conditions.

3.10A.5 MAKEUP WATER SUPPLY STORAGE POND ANALYSIS

The makeup water supply storage pond is designed to comply with all federal, state, and local regulations regarding the concept of zero discharge. Runoff from the central plant area (approximately 200 acres) will be directed to the makeup water supply storage pond. A portion of the runoff retained in the pond will either evaporate or be allowed to seep.

Some of the water that seeps out of the pond will emerge at the surface on the downstream side of the embankment and flow to natural drainage systems within the area.

Several pond configurations were analyzed. The analysis was based on pond storage capacity as well as environmental desirability. The pond configuration considered to be the most appropriate is shown on Figure 3.10-1. The pond shown has a surface area of approximately 93 acres and an embankment length of about 10,000 feet. Approximately 230 inches ($_4P_{25}$) of precipi- 5
tation was routed through the pond in two separate four-year sequences as indicated in Table 3.10A-5. These sequences are considered to represent the most extreme cases of the $_4P_{25}$. It can be seen that in Sequence A, the $_2P_{25}$ occurs in the first two years, while in Sequence B, the $_2P_{25}$ occurs in the last 2 years.

The 4-year interval was selected because the most crucial period for the water surface elevation within the makeup water supply storage pond will occur during Unit 1 construction. During plant operation, excess amounts of runoff will be consumed as cooling tower makeup.

Routing computations were based on a calendar year being divided into twenty-four 15-day periods. Total annual precipitation was divided into 24 separate precipitation events whose distribution was based on observed monthly precipitation distribution for Orlando (Table 3.10A-2). The initial 5
precipitation event and the runoff associated with it were considered to occur instantaneously at the beginning of the first 15-day period. The beginning of period stage was then determined from the previously defined stage-capacity relationship shown in Figure 3.10A-1. The total volume of seepage was determined through the use of a seepage-stage relationship. Evaporation was also determined for each period in a manner similar to that used for precipitation. Subtracting the total volume of seepage and evaporation from the beginning of period storage volume yielded the volume of water within the makeup water supply storage pond at the end of the first period. Second period precipitation and runoff were then added to this value to obtain the beginning of period storage volume for the second period. In this manner, total annual precipitation was routed through the pond, with allowances made for seasonal evaporation and variable seepage

rates. Pond elevations, with respect to time, are shown for precipitation Sequences A and B in Figures 3.10A-2 and 3.10A-3, respectively.

The maximum potential water surface elevation within the makeup water supply storage pond during Unit 1 construction was determined to be approximately 77.7 feet. This maximum elevation corresponds to a total 4-year
precipitation of about 230 inches, distributed according to precipitation 5
Sequence B. This total 4-year precipitation is considered to have a re-
currence interval of approximately 25 years. The pond embankment will be 5
constructed to a crest elevation of 80 feet. This will provide for a computed freeboard requirement of 2.8 feet, based on a sustained wind velocity of 100 miles per hour and an effective fetch length of approximately 1,800 feet.

TABLE 3.10A-1. DERIVED PRECIPITATION DATA

Description	Designation	Precipitation inches
Total annual precipitation having a 25-year recurrence interval	$_1P_{25}$	67.0
Total precipitation for two successive years having a 25-year recurrence interval	$_2P_{25}$	125
Total precipitation for four successive years having a 25-year recurrence interval	$_4P_{25}$	230

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TABLE 3.10A-2. MONTHLY PRECIPITATION DISTRIBUTION FOR THREE AMOUNTS OF TOTAL ANNUAL PRECIPITATION

	Total Annual Precipitation			
Month	Normal inches	$_1P_{10}$* inches	$_1P_{33}$** inches	
January	2.28	2.7	2.98	
February	2.95	3.49	3.86	
March	3.46	4.09	4.53	
April	2.72	3.22	3.56	
May	2.94	3.48	3.85	
June	7.11	8.41	9.3	
July	8.29	9.81	10.85	5
August	6.73	7.96	8.81	
September	7.20	8.52	9.42	
October	4.07	4.82	5.32	
November	1.56	1.85	2.03	
December	1.9	2.25	2.49	
Annual	51.21	60.6	67.0	

*Distribution based on ratio of $_1P_{10}$ to $_1P_{2.5}$ times monthly normal rainfall in Orlando.

**Distribution based on ratio of $_1P_{33}$ to $_1P_{2.5}$ times monthly normal rainfall in Orlando.

TABLE 3.10A-3. EXISTING ANNUAL RUNOFF RATIOS AT GAGING STATIONS IN VICINITY OF PROPOSED SITE

Gaging Station Name	Average for Period of Record	1958 Precipitation = 51.2 in.	1959 Precipitation = 63.77 in.	1960 Precipitation = 68.74 in.**
Little Econlockhatchee River near Union Park, Florida	0.25	*	*	0.38
Econlockhatchee River near Chuluota, Florida	0.29	0.26	0.38	0.56

*Streamflow records not available.

**Maximum annual precipitation for period of record (1940-present) measured at Orlando, Florida.

TABLE 3.10A-4. EXISTING AND ADJUSTED ANNUAL RUNOFF RATIOS FOR THE ECONLOCKHATCHEE RIVER NEAR CHULUOTA, FLORIDA

Item	Existing Runoff Ratio	Adjusted Runoff Ratio*
Average for period of record, in.	0.29	0.14
1958--Precipitation = 51.2 in.	0.26	0.10
1959--Precipitation = 63.77 in.	0.38	0.26
1960--Precipitation = 68.74	0.56	0.44

*Computed by assuming an additional 8 inches of annual precipitation infiltrates into the soil due to added fill over water table.

TABLE 3.10A-5. FOUR-YEAR PRECIPITATION SEQUENCES HAVING A 25-YEAR RECURRENCE INTERVAL 5

Sequence	Total Annual Precipitation, inches				
	Year 1	Year 2	Year 3	Year 4	Total
A	60.6	67.0	51.21	51.21	230.02
Recurrence Interval, years	10	25	2.5	2.5	25
--------------------------	------	------	------	------	------
B	51.21	51.21	60.6	67.0	230.02
Recurrence Interval, years	2.5	2.5	10	25	25

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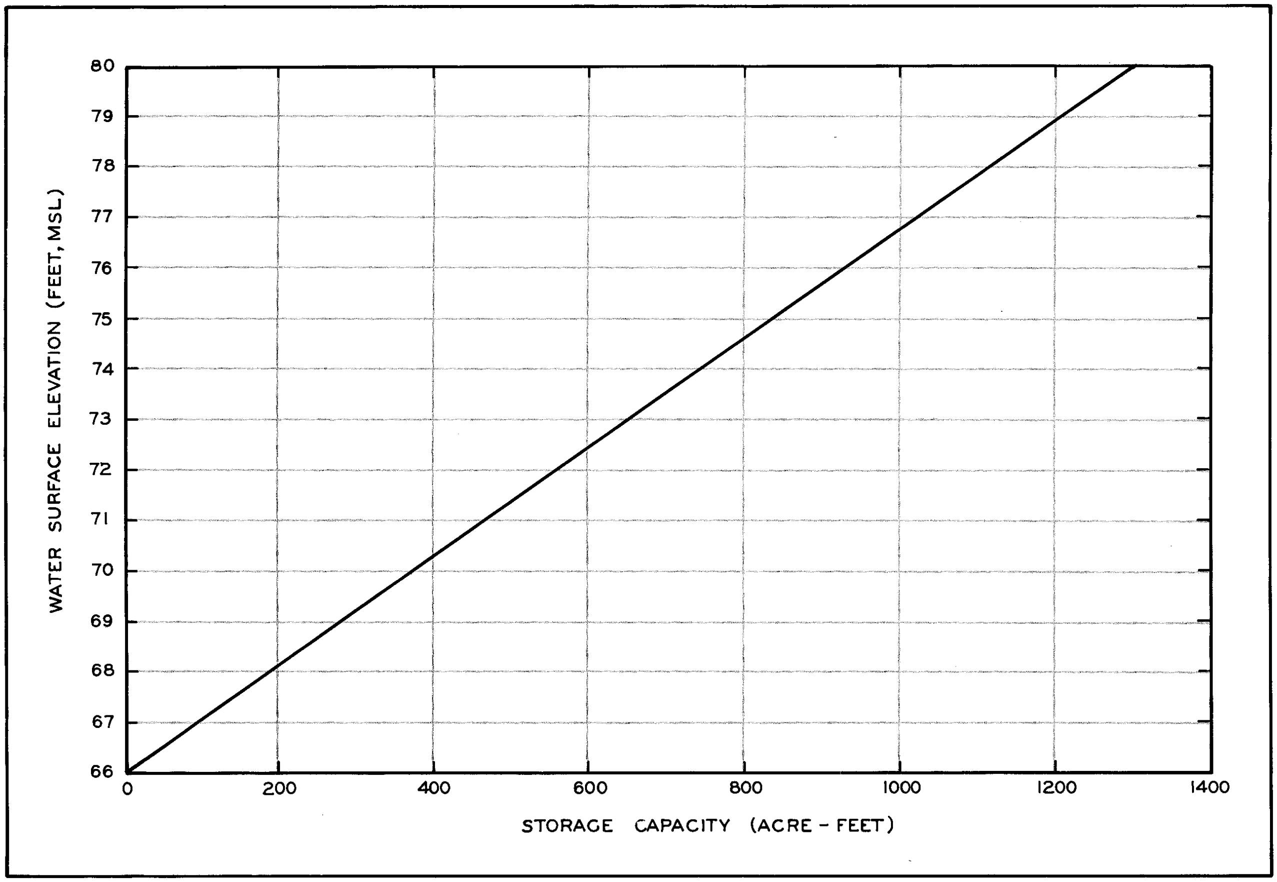

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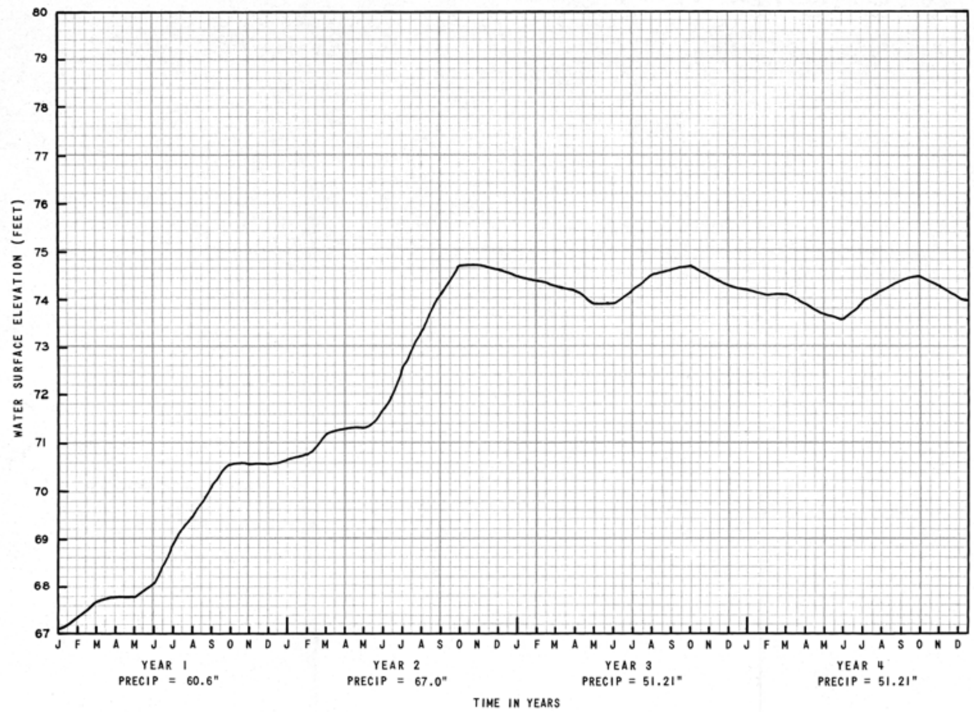
FIGURE 3.10A-1. STAGE - STORAGE CURVE FOR MAKEUP WATER SUPPLY STORAGE POND



NOTE: WATER SURFACE ELEVATION REPRESENTS BEGINNING OF PERIOD VALUES

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FIGURE 3.10A-2. MAKEUP WATER SUPPLY STORAGE POND STAGE PRECIPITATION SEQUENCE A

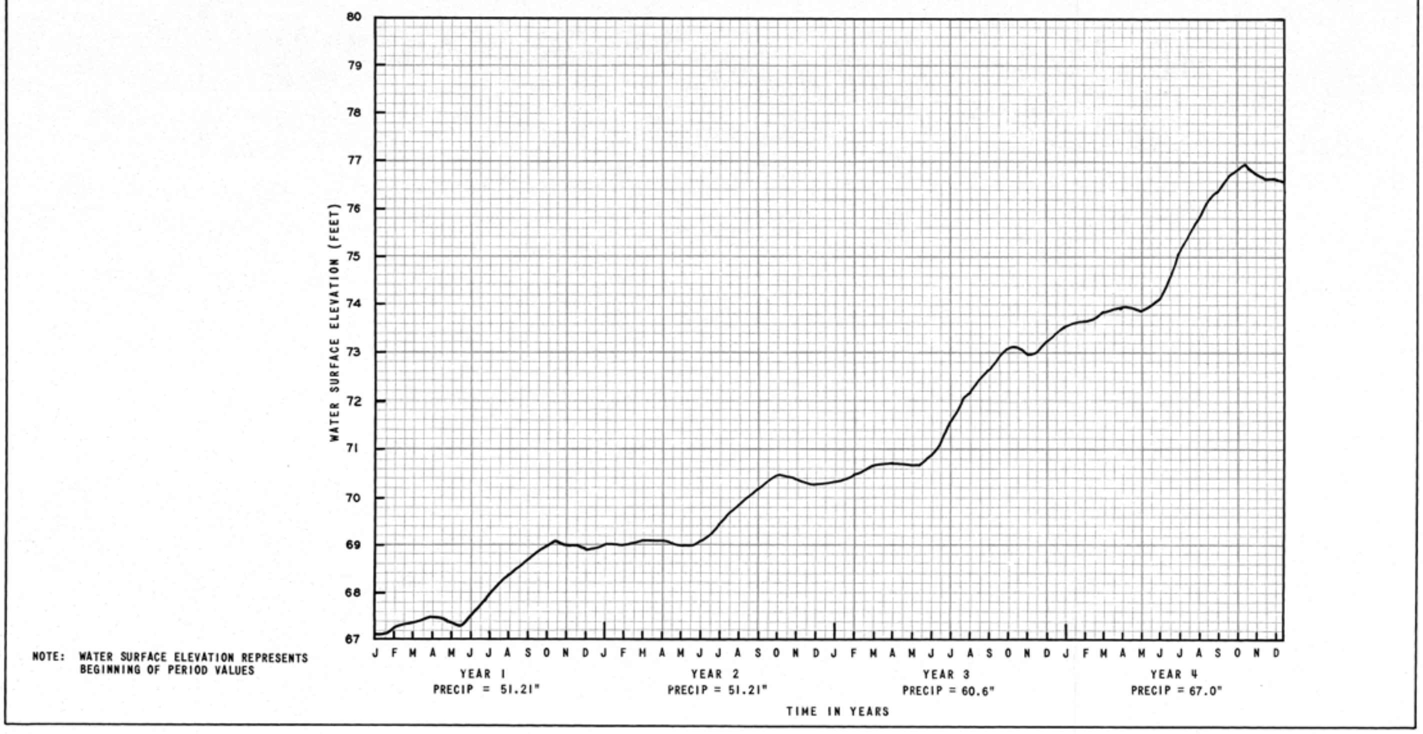

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FIGURE 3.10A-3. MAKEUP WATER SUPPLY STORAGE POND STAGE PRECIPITATION SEQUENCE B

3.11 DESIGN ALTERNATIVES

The following sections describe various design alternatives considered in the development of the conceptual design of Stanton Energy Center Unit 1. The following alternatives are ones that have potential environmental effects. Numerous other design evaluations which do not have an environmental impact were performed but are not presented here.

3.11.1 Alternate Site Arrangements

The evaluation of an optimum site arrangement requires study of the relationships between major systems of the units and the physical characteristics of the site. The selection of the optimum site arrangement is based on site characteristics and the functional and physical relationship of the plant system.

3.11.1.1 Site Characteristics.

3.11.1.1.1 Location. The site is located roughly 12 miles southeast of Orlando. The site is bounded as follows.

(1) To the north by the Pershing Substation-to-Indian River transmission corridor, Highway 50, and some developed areas.

(2) To the east by the Econlockhatchee River.

(3) To the south by the Bee Line Expressway.

(4) To the west by the Orange County sanitary landfill.

3.11.1.1.2 Topography. A gradual slope across the site from southwest to northeast provides a means for drainage during heavy rainfall and prevents excessive flooding during flood conditions on most areas of the site. The soil at ground surface consists of fine sand generally covered with grass vegetation. The ground water table is located 1 to 6 feet below ground surface varying with location within the site and fluctuating from season to season.

Locating the plant near the east boundary is avoided since the area is prone to flooding. Locating the plant near the central portion of the site allows a means for the southwest to northeast drainage to be collected and stored by placing the retention areas east of the plant.

Scattered areas throughout the site that do not drain well are often wet and tend to support a great deal of vegetation and offer protection for certain wildlife. These areas are avoided whenever possible so as to not adversely effect the overall ecology of the site.

3.11.1.1.3 Critical Wildlife Present Onsite. The wildlife species considered critical with respect to the impact on site arrangement is the red-cockaded woodpecker.

It is the intent of this analysis to develop a site arrangement compatible with the habitat of the wildlife such that the impacts on cavity trees and foraging areas are minimized.

3.11.1.1.4 Climate. A review of wind data collected over a 30-year period indicates that the wind is predominantly out of the north, northeast, east, southeast, or south depending on season.

Analysis of cooling tower fallout and its impact on the electrical equipment, combined with the consideration of the boiler structure ventilation system, indicates a building arrangement with gas flow from east to west (i.e. Turbine Building facing east with the boiler, gas cleaning equipment, and chimneys following in a westerly direction) to be favorable. The basic arrangement is developed with this in mind, providing that the major systems external to the main generating complex may exit the plant in an organized radial manner and are compatible with their destination off-site or outside of the main complex.

Other climatological data such as rainfall, temperature, evaporation, etc., does not have a major impact on the actual site arrangement other than the sizing of various ponds and the design of site drainage.

3.11.1.1.5 Existing Transmission. The plant site is situated directly south of the existing transmission corridor running from Pershing Substation to the Indian River Power Plant. Transmission lines exiting the site would extend north to the existing corridor. Locating the substation to the north side of the generation facilities with transmission exiting the substation to the north provides the most economical arrangement.

3.11.1.1.6 Transportation. The proposed location of the main plant access road is north of the site. The road would run south from Highway 50 (Cheney Highway) along the proposed makeup pipeline corridor to the existing transmission corridor and on to the site. The road would be approximately 8 miles in length from Highway 50 to the generation facilities.

The proposed routing of the coal supply and material delivery railroad spur to the site is from the west. The routing to the west (SCL Railroad) was selected since the environmental impacts and the costs of construction to the east (FEC Railroad) are much greater. The proposed spur would originate at a turnout from the Seaboard Coast Line Railroad mainline approximately 1 mile southwest of the Orlando International Airport. The spur would be required to cross under the Bee Line Expressway at an existing interchange just south of the site. With the coal delivery spur entering the south, the most advantageous location for the coal delivery loop would be the south side of the plant.

3.11.1.1.7 Miscellaneous Considerations. The cooling system makeup water source will be effluent from the Iron Bridge Road Regional Water Pollution Control Facility located north of the proposed site on the north side of the Little Econlockhatchee River. The pipeline will enter the site from the north using the same corridor as the access road and the transmission lines. Locating the makeup water supply storage pond toward the north side of the site would help to minimize makeup piping length.

Potable water will be obtained from an onsite well field and will not impact on the overall site arrangement.

A dry solid waste storage area will be located within the boundaries of the plant site. A sanitary landfill currently in operation is located approximately one mile west of the proposed plant site. Locating the solid waste storage area adjacent to the landfill with the plant east of the solid waste storage area is preferred as compared to locating the plant near the landfill. This arrangement readily conforms to the east-west orientation and the radial concept. In addition, this concept would also result in the Administration and Plant Services Building being the furthest possible distance from the combustion waste storage area and sanitary landfill.

3.11.1.2 Alternative Site Arrangements. Having given consideration to those facts previously presented concerning site topography, wildlife, climatology, existing transmission, and transportation systems, three basic arrangements were developed for final consideration. Plans A, B, and C appear on Figures 3.11-1, 3.11-2, and 3.11-3, respectively. Plan A was included mainly for purposes of comparison since it is based purely on economics and neglects those requirements previously included for climatological and environmental purposes. Plans B and C attempt to satisfy all of those requirements developed herein. Table 3.11-1 provides the estimated comparative cost of construction for the three plans. The results indicate Plan B to be the most economical of those plans considered acceptable. In addition, the results indicate that for the additional cost of approximately $4,514,000 (Plan A vs. Plan B), the Generation Building ventilation is improved; dust from the coal handling operation will be directed away from the building by the prevailing winds, and all but one of the active red cockaded woodpecker cavity trees can be avoided.

3.11.2 Alternative Heat Rejection Systems

Waste heat from the condensation of exhausted steam in the circulating water system must be transferred to the atmosphere by a heat rejection system. Several systems have been developed to transfer this heat either directly to the atmosphere or through large bodies of water.

3.11.2.1 Heat Rejection System Design Alternatives.

3.11.2.1.1 Once-Through Cooling. This cooling process pumps water from a river, lake, or pond through the condenser, and discharges the cooling water back to the source. This alternative requires the plant to be close to a river or lake or that a cooling pond be developed onsite. Since Stanton Energy Center is not close to a lake or river, a cooling pond would have to be developed onsite. Due to the environmental effects of covering a large area of the site (approximately 700 acres) with a cooling pond and the high capital cost of cooling ponds, once-through cooling was not considered a viable heat rejection system.

3.11.2.1.2 Dry and Wet/Dry Cooling Towers. Dry cooling towers do not depend upon water evaporation for cooling. Heat is dissipated from the condenser cooling water by conduction and convection directly to the ambient atmosphere. Heated cooling water from the condensers is pumped through banks of finned-tube heat exchangers. The heat in the water is transferred by conduction to the metal walls of the finned-tubing and is dissipated to the atmosphere.

This system is advantageous in areas where cooling water supplies are limited since the system does not require makeup to replace water lost by evaporation. However this system requires a vary large physical structure and is very costly both in terms of initial expenditures and high plant auxiliary power requirements.

Wet-dry cooling towers utilize a combination of dry and evaporative cooling. One type of wet-dry tower is a parallel path tower in which water is cooled first in a dry air-cooled section and then in a wet section. The air leaving the dry section and entering the wet is at a higher dry bulb temperature but much lower humidity than air in the wet section. Consequently, mixing occurs and the resulting air leaving the tower is in a warm but unsaturated condition. Evaporation is reduced and makeup requirements are minimized. This system is advantageous where a makeup water source is limited or fogging effects are important. Neither dry nor wet/dry cooling towers are considered viable alternatives for Stanton Energy Center since capital and operating costs are high and an adequate supply of water for cooling tower makeup is available.

3.11.2.1.3 Natural Draft Cooling Towers. Wet natural draft cooling towers utilize a large chimney to create an upward draft which pulls air through the tower fill. Circulating water is pumped to the fill elevation of the tower and allowed to fall. Water is distributed over the fill and heat exchange occurs by evaporation and convection. The difference in density between the warm air inside the tower and the cooler air outside creates a draft and airflow is established without employing mechanical draft fans. Recent escalation in fuel costs has increased the feasibility of natural draft towers in utility applications since energy is not required for fan operation. However, the structure is large and initial capital costs are high. A natural draft cooling tower is considered a viable alternative for Stanton Energy Center.

3.11.2.1.4 Mechanical Draft Cooling Towers. Multifan mechanical draft cooling towers have been used extensively for power plant heat rejection systems. Mechanical draft towers use large fans to pull air over the tower fill. Water is distributed over the fill and heat exchange takes place by evaporation and convection. Since airflow is produced by mechanical fans, the structure of the tower is smaller than a natural draft tower and initial capital costs are lower.

Both rectangular mechanical draft towers and round mechanical draft towers have been utilized. Round towers have proven advantages over conventional rectangular towers, including plume consolidation which minimizes fogging and drifting. Round mechanical draft towers are considered a viable alternative for Stanton Energy Center.

3.11.2.2 Description of Viable Heat Rejection Systems. Two heat rejection systems are considered to be viable alternatives for Stanton Energy Center Unit 1: a natural draft cooling tower and a round mechanical draft cooling tower.

3.11.2.2.1 Natural Draft Cooling Tower. The site arrangement of the natural draft cooling tower for Stanton Enegy Center Unit 1 would be as shown in Figure 3.11-4. The tower would have a height of approximately 370 feet. This height would reduce fogging and drift on plant facilities, therefore, the tower can be located closer to the plant, resulting in shorter lengths of circulating water pipe.

3.11.2.2.2 Round Mechanical Draft Cooling Tower. The site arrangement of round mechanical draft cooling tower would be as shown on Figure 3.11-5. The tower would be approximately 60 feet high. Mechanical draft cooling towers have greater fogging and drift effects than natural draft cooling towers and therefore, must be located farther away from the plant.

3.11.2.3 Comparison of Viable Heat Rejection Systems. The comparative capital costs and annual costs of the round mechanical and natural draft tower are presented in Tables 3.11-2. Initial capital costs are lower for the round mechanical draft tower than the natural draft tower; however, annual costs are higher. The results of a capital recovery analysis which considers initial capital cost versus operating cost indicates the natural draft cooling tower is more economical than round mechanical draft tower after the eighth year of operation.

The tall natural draft tower causes less ground fog and drift and is more economical with a short payment period. Based on these considerations, the most advantageous heat rejection system is a natural draft cooling tower.

3.11.3 Alternate Air Quality Control Systems

The air quality control system will consist of an electrostatic precipitator and a limestone scrubber. Evaluation of alternate air quality control systems is presented in Section 3.7.

3.11.4 Alternate Wastewater Disposal Methods

The water balance at Stanton Energy Center results in an excess of wastewater that must be disposed of or treated and reused. The excess wastewater consists mostly of cooling tower blowdown. The following methods of wastewater management were considered.

3.11.4.1 Return Pipeline. The excess cooling tower blowdown would be returned to the Iron Bridge Road Regional Water Pollution Control Facility. The excess blowdown would be routed to a pump pit. From the pump pit, the blowdown would be pumped back to the Iron Bridge Facility in a 10-inch return pipeline that would parallel the makeup water supply pipeline.

3.11.4.2 Pretreatment of Circulating Water Makeup. By adding commercial grade quicklime, CaO, or hydrated lime, $Ca(OH)_2$, the "carbonate hardness" of the makeup water can be reduced. "Carbonate hardness" consists of the carbonate and bicarbonate salts of calcium and magnesium. Treatment would take place in a conventional solids contact basin type clarifier. A coagulant and/or a coagulant aid would be fed to facilitate coagulation and settling. The degree of hardness removal may be improved by feeding soda ash, Na_2CO_3, in addition to lime. Soda ash reacts to remove the non-alkalinity related calcium and magnesium.

However, since silica is limiting in determining cycles of concentration and therefore the blowdown required at the Stanton Energy Center, the pretreatment system employed must also remove silica. Silica can be removed by adsorption onto the magnesium hydroxide floc produced in the softening and coagulation process. Due to the limited magnesium present in the sewage effluent, there would be a limited amount of silica reduction achievable in a conventional solids contact basin utilizing lime-soda ash softening. With 16.5 mg/l silica as SiO_2 in the circulating water makeup, it is anticipated that silica could be reduced to about 12 mg/l as SiO_2 with conventional lime-soda ash softening. Reducing the silica concentration from 16.5 to 12 mg/l would allow an increase in the cycles of concentration from 9 to 12.5.

If cycles of concentration were increased to 12.5 in the circulating water systems, the amount of wastewater to be returned to the Iron Bridge Facility would be decreased. The resulting pipeline size for the return line to the STP could be reduced from 10 inches to 6 inches resulting in a capital cost savings of approximately $2,800,000. A 1987 capital cost for pretreatment systems for all four generating units is estimated at approximately $5,500,000, which is in excess of the reduced capital costs associated with the smaller return line. In addition, the operating costs for a pretreatment plant would be considerable for chemicals, labor, and maintenance. For these reasons pretreatment was not considered a viable alternative for Stanton Energy Center.

3.11.4.3 Sidestream Treatment of Circulating Water by the Lime-Soda Ash Dense Solids Process. By taking a portion of the circulating water, removing calcium and silica in the stream, and returning the stream back to the circulating water systems, the cooling tower systems can be operated at higher cycles of concentration, thereby minimizing cooling tower blowdown.

Sidestream treatment would involve feeding lime and soda ash in a dense solids treatment system. The lime-soda ash dense solids treatment process uses a modified solids contact basin design, whereby a high solids concentration is maintained in the reaction zone to accomplish two objectives.

(1) The increased solids provide more reaction sites which improve the efficiency of hardness removal reactions.

(2) Magnesium hydroxide floc present in the recirculated sludge provides additional adsorption sites for silica, and consequently, results in improved silica removal.

Certain circulating water inhibitors may affect the results of treatment with this method by retarding the normal softening reactions. Substances contained in the STP effluent may also be present which affect the softening reactions. The presence of high density sludge in the mixing and reaction zones may help to overcome this effect.

3.11.4.4 Wastewater Treatment by the Lime-Soda Ash Dense Solids Process. This method of wastewater treatment is similar to the methods discussed in Subsection 3.11.4.3. However, instead of using sidestream treatment, an alternate arrangement of directing the circulating water blowdown streams to the recycle basin would be used. Water from the recycle basin would be treated by the lime-soda ash dense solids process for reuse in the circulating water systems. Several advantages of this arrangement are as follows.

(1) The treatment facility for all four units could be installed at one central location avoiding a separate sidestream treatment facility for each unit.

(2) The treatment plant will treat all waste streams directed to the recycle basin, although the majority of the recycle basin influent will still be circulating water blowdown.

(3) The surge capability of the recycle basin provides flexibility which may affect the selection of the size of the treatment facility.

(4) The effluent from the lime-soda ash dense solids treatment plant may be directed to the makeup water supply storage pond rather than directly to the circulating water systems which would allow operation of the treatment facility when the unit or units are down or at a low load.

The lime-soda dense solids treatment process would be similar to that described under Section 3.11.4.3, with the same disadvantages and possible problems including the following.

(1) It may be difficult to remove sufficient quantities of silica to make this a feasible process.

(2) Inhibitors contained in the circulating water may affect the results of treatment with this method.

(3) Substances contained in the pollution control facility effluent may be present which affect the softening reactions.

3.11.4.5 Wastewater Treatment Utilizing Reverse Osmosis and Brine Concentrators. Another method of wastewater treatment is to treat excess wastewater utilizing reverse osmosis and brine concentrators to achieve zero plant discharge. Reverse osmosis product water would be suitable to be directed back to the makeup water supply storage pond and the reject brine would be directed to brine concentrator system. Product water from the brine concentrators will be low in total dissolved solids and will be directed to the demineralization system to take advantage of regenerant chemical savings. The small quantity of highly concentrated brine reject could be used as wetting water for solids waste disposal or dried to a solid. Due to the silica present in the wastewater to be treated and the suspended solids limitations of reverse osmosis, lime-soda ash pretreatment and filtration would be required preceeding the reverse osmosis units. Circulating water and recycle basin TDS would not be affected under this alternative.

The 1987 capital cost of this plan is estimated to be in excess of $13,000,000. The high capital costs and high operating costs, including maintenance and labor costs, reverse osmosis membrane replacement costs, and the energy costs for operating a reverse osmosis and brine concentrator systems, makes this plan unattractive in comparison to other alternatives. Therefore, this plan is not given additional consideration.

3.11.4.6 Viable Alternate Plans. The following two plans were given detailed consideration.

(1) Return Pipeline. All wastewater not reused at the site will be returned to the Iron Bridge Road Regional Water Pollution Control Facility. This primarily will consist of excess cooling tower blowdown. It is anticipated that a single 10 inch return line will be capable of handling the wastewater from four 460 MW gross units.

(2) Wastewater Treatment. Under this plan, a lime-soda ash dense solids process treatment plant would treat excess waste water from the recycle basin and return it to the makeup water supply storage pond for reuse in the circulating water systems. The system would have the capability of treating approximately 1,500 gpm of excess wastewater. A wastewater return line to the Iron Bridge Facility is not utilized in this plan.

3.11.4.7 Comparative Costs. The comparative capital and annual costs of the two plans are shown in Table 3.11-3.

Annual operating costs for the plans will vary according to the number of units in service, and the unit capacity factors applied. Table 3.11-3 shows the comparative annual costs of operation of the two plans, assuming four units are operating at a 53.6 per cent capacity factor.

A capital recovery analysis was performed to determine in which year the cumulative present worth savings of the reduced operating costs would equal the 30-year cumulative present worth of the additional fixed charges. The results show that the pipeline plan will pay for itself, due to reduced operating costs during the 6th year of operation.

3.11.5 Discussion and Conclusion

The economic analysis shows that the 10-inch return pipeline to the Iron Bridge Facility will have greater capital costs than utilizing a lime-soda dense solids wastewater treatment facility with no return pipeline. However, on an annual cost basis, the wastewater return pipeline will be more economical.

Additional factors favoring the installation of the wastewater return pipeline over the wastewater treatment plan are as follows.

(1) The return pipeline will be less susceptible to operational problems and equipment failure due to its simplicity of operation.

(2) The return pipeline will be able to handle more easily the upsets caused by environmental factors, such as periods of heavy rainfall.

(3) The circulating water will be lower in total dissolved solids, resulting in less exotic materials of construction for circulating water system and scrubber components. In addition, should there be any condenser leakage, the steam cycle water chemistry will be less affected and the condensate polishing system will be more capable of removing the contaminants.

(4) The wastewater treatment plan utilizes a technology in which there is relatively little experience. The capability of the

lime-soda ash dense solids process for treating wastewater, which is largely concentrated secondary sewage treatment plant effluent containing added chemical inhibitors, is not clearly proven.

3.11.6 Alternate Site Access Road Location

Three options were considered for providing access to the site as shown on Figure 3.11-6. Plan A, as shown, would extend south from Highway 50 (Cheney Highway) along the proposed makeup pipeline corridor to the existing transmission corridor and on to the site. Plan A would also provide right-of-way and a means for maintenance access to the proposed makeup pipeline. Plan B would follow the existing transmission corridor to the site. Plan C would exit from the Bee Line Expressway and run north to the site. A disadvantage exists for Plan C in the fact that the Bee Line is a toll road. Likewise, Plan C enters the site from the south while the majority of the work force will most likely live northwest of the plant. However, Plan C is slightly shorter. Similarly, a disadvantage exists for Plan B in the fact that the road from which it originates is lined with housing, is not a quality road, and would not provide the ease of access that Highway 50 (Plan A) would. Table 3.11-4 provides the estimated comparative construction costs for the three plans. Based upon initial cost, Plan A is the most economical and is recommended as it would provide a practical access to the site.

3.11.7 Alternate Bottom Ash Systems

3.11.7.1 Overall Ash Handling. Bottom ash that falls from the boiler is collected in a water filled hopper at the bottom of the boiler. Two alternate methods of removing the bottom ash from the bottom ash hopper were considered: mechanical drag line and hydraulic sluicing. The mechanical drag line method of ash removal is presently not in operation in the United States. Due to its lack of experience with U.S. coal, it was not considered further. Hydraulic sluicing of the bottom ash will be used. The bottom ash will be sluiced from the bottom ash hopper to a transfer tank. From the transfer tank, the bottom ash will be slurry pumped to temporary storage and dewatering facilities. Two methods of temporary storage and dewatering were considered: dewatering bins and lined ponds.

3.11.7.2 Dewatering Bins. Two dewatering bins would be provided with Unit 1. The bottom ash would be slurry pumped from the bottom ash transfer tank to the dewatering bins. The water from the bins would be clarified and reused. The bottom ash would be removed daily from the dewatering bins and trucked to the onsite landfill area.

3.11.7.3 Ponds. Two ponds, each capable of holding six months of ash production, would be provided. The bottom ash would be slurry pumped from the bottom ash transfer tank to the ponds. The water from the pond would be clarified and reused. The bottom ash would be removed from the ponds once a year and trucked to the onsite landfill area.

3.11.7.4 Comparative Costs. The comparative annual and capital costs of using dewatering bins or lined ponds is shown in Table 3.11-5. The dewatering bins are the most economical and therefore, will be used for bottom ash dewatering and temporary storage. The dewatering bins are also more environmentally desirable since ash pond liners could be damaged during ash removal.

3.11.8 Alternate Coal Handling Systems

The coal will be received by unit train and unloaded by a bottom dump unloading system. The coal will be stocked out and retrieved from the active coal pile by the coal stockout and reclaim system.

Four alternate stockout and reclaim plans were considered and are listed as follows.

(1) Plan A--Elevated tripper and rotary plow feeder reclaim as shown in Figure 3.11-7.
(2) Plan B--Stacker-reclaimer as shown in Figure 3.11-8.
(3) Plan C--Silo active storage with vibratory feeder reclaim as shown in Figure 3.11-9.

(4) Plan D--Barn active storage and rotary plow feeder reclaim as shown in Figure 3.11-10.

The comparative capital and annual costs of these four plans are shown on Tables 3.11-6 and 3.11-7, respectively. Plan B, the stacker-reclaimer, has the lowest capital and annual costs. The major disadvantage of Plan B is that it offers less control of fugitive dust than do Plans C and D which have coal unloading and reclaim in an enclosed area. Dust control for Plan B will consist of a water spray arranged to fog the area of material disturbance during reclaim operations and keeping the machine boom as close as possible to the job during stockout operations. The fugitive coal dust of the stacker-reclaimer arrangement is not expected to be a problem as indicated in Section 5.5. Therefore, the added costs of Plans C and D are not justified and the stacker-reclaimer will be used for coal stockout and reclaim.

3.11.9 <u>Alternate Auxiliary Steam Systems</u>

Auxiliary steam is required during startup of the unit. The auxiliary steam demands can be met with commercially available packaged oil-fired, electric, and in some cases coal-fired boilers. Only oil-fired and electric boilers are considered feasible for providing the auxiliary steam requirements for Stanton Energy Center Unit 1. Coal-fired auxiliary boilers are not feasible for the following reasons.

(1) The addition of a second unit at the Stanton Energy Center site will reduce and may eliminate the need for the auxiliary boiler. Minimizing the amount of capital investment for an auxiliary boiler would be advantageous. By comparison, the present day capital cost for an oil-fired auxiliary boiler is between 2 to 3 dollars per pound of steam, and 18 to 22 dollars per pound for a coal-fired auxiliary boiler.

(2) Required coal handling and ash handling systems would increase plant space and maintenance requirements.

Oil-fired boilers considered for evaluation are factory-assembled, pressurized furnace, water tube type, with superheat capability designed for Number 2 or Number 6 fuel. Electric boilers considered for evaluation are factory-assembled, single drum, high voltage electrode type, designed for operation with a 13.2 kV, three-phase power supply.

The comparative capital and annual costs are shown in Table 3.11-8. The Number 2 Fuel Oil auxiliary boiler has the lowest capital and annual costs and therefore, will be used to supply the auxiliary steam requirements for Stanton Energy Center Unit 1. The Number 2 Fuel Oil auxiliary boiler is expected to have the least environmental effect since Number 6 fuel oil contains more ash and sulfur than Number 2 fuel oil and the Number 2 fuel oil auxiliary boiler (approximately 86 per cent efficient) would have a greater efficiency than the electrode auxiliary boiler (typical power plant which would supply electricity to the electric boiler is 35-40 per cent efficient).

TABLE 3.11-1. COMPARATIVE CAPITAL COST EVALUATION FOR VARIOUS SITE ARRANGEMENTS

Item	Plan A* $1,000	Plan B $1,000	Plan C $1,000
Transmission	Base	2,052	2,052
Access Road	Base	408	408
Railroad	260	Base	510
Water Supply Pipeline	Base	420	420
Coal, Limestone, and Solid Waste Handling Systems	Base	1,980	3,520
Site Clearing	86	Base	98
Total Comparative Cost (1980 dollars)	346	4,860	7,008
Total Differential Comparative Cost	Base	4,514	6,662

*Plan A neglects Climatological and Environmental requirements.

TABLE 3.11-2. COMPARATIVE CAPITAL AND ANNUAL COSTS OF ROUND MECHANICAL AND NATURAL DRAFT TOWERS

	Round Mechanical Draft $	Natural Draft $
Capital Costs		
Cooling Tower	Base	4,436,000
Electrical Construction	512,000	Base
Condenser	Base	Base
Circulating Water Pipe	644,000	Base
Circulating Water Pumps and Motors	19,000	Base
Auxiliary Cooling System	Base	Base
Direct Costs	1,175,000	4,436,000
Escalation	551,000	2,081,000
Escalated Direct Costs	1,726,000	6,517,000
Sales Tax	69,000	261,000
Indirects	323,000	1,220,000
Interest During Construction	108,000	408,000
Total Comparative Capital Cost	2,226,000	8,406,000
Differential Total Comparative Capital Costs	Base	6,180,000
Annual Costs		
Fixed Charge	Base	630,000
Energy Cost	1,183,000	Base
Demand Charge	305,000	Base
Fuel Cost	120,000	Base
Maintenance	105,000	Base
Total Comparative Annual Cost	1,713,000	630,000
Differential of Comparative Annual Cost	1,183,000	Base

TABLE 3.11-3. COMPARATIVE CAPITAL AND ANNUAL COSTS 10" RETURN PIPELINE VS. A LIME-SODA ASH DENSE SOLIDS WASTEWATER TREATMENT SYSTEM

Item	10" Wastewater Return Pipeline $1,000	Lime-Soda Ash Dense Solids Wastewater Treatment $1,000
CAPITAL COSTS		
Piping, valves, and fittings	2,395	Base
Dense Solids Wastewater Treatment System	--	830
Pumps and pump structures	15	Base
Building costs	--	216
Chemical storage facilities	--	120
Erection	1,219	Base
Direct costs subtotal	3,629	1,166
Escalation	942	303
Interest during construction	411	132
Indirect costs	549	176
Sales tax	108	43
Comparative capital costs	5,639	1,820
Differential capital costs	3,819	Base
ANNUAL COSTS		
Chemical costs	Base	1,131
Labor costs	Base	351
Energy costs	Base	13
Demand costs	18	Base
Comparative annual costs of operation	18	1,495
Differential annual costs of operation	Base	1,477
Fixed charges	443	Base
Total annual costs	443	1,477
Differential total annual cost	Base	1,034

TABLE 3.11-4. COMPARATIVE CAPITAL COST EVALUATION FOR ACCESS ROAD

Item	Plan A $	Plan B $	Plan C $
Right-of-way	90,000	80,000	Base
Earthwork	Base	65,000	155,000
Subgrade and paving	295,000	145,000	Base
Drainage structures	Base	20,000	30,000
Seeding	10,000	10,000	Base
Fencing	80,000	70,000	Base
Makeup pipeline right-of-way and maintenance access road	Base	200,000	400,000
Total comparative cost (1981 dollars)	475,000	590,000	585,000
Differential total comparative cost	Base	115,000	110,000

TABLE 3.11-5. BOTTOM ASH SYSTEM COMPARATIVE CAPITAL AND ANNUAL COSTS

Item	Slurry Pumps to Dewatering Bins $1,000	Slurry Pumps to Ash Pond $1,000
CAPITAL COST		
Material and Erection	943	Base
Escalation	488	Base
Escalated Subtotal	1,431	Base
Sales Tax	58	Base
Interest During Construction	90	Base
Indirect Costs	258	Base
Total Comparative Capital Cost	1,837	Base
LEVELIZED ANNUAL COST		
Fixed Charge	187	Base
Demand Charge	Base	Base
Energy Charge	Base	Base
Operation and Maintenance Costs	Base	338
Total Comparative Levelized Annual Cost	187	338
Differential Levelized Annual Cost	Base	151

TABLE 3.11-6. COMPARATIVE COSTS--STOCKOUT AND RECLAIM PLANS

	Plan A Elevated Tripper $	Plan B Stacker Reclaimer $	Plan C Silo $	Plan D Barn $
Conveyors	878,000	500,000	Base	629,000
Conveyor Structures	125,000	Base	698,000	274,000
Transfer Structures	Base	135,000	673,000	Base
Enclosed Storage Structure	--	--	5,290,000	5,513,000
Traveling Tripper	165,000	--	--	165,000
Feeders and Gates	Base	84,000	342,000	84,000
Plow Feeders	360,000	--	--	360,000
Fire Protection	117,000	41,000	Base	90,000
Dust Collection	105,000	Base	504,000	791,000
Electrical	Base	20,000	23,000	33,000
Reserve Reclaim Structure	--	1,102,000	1,102,000	1,102,000
Stacker Reclaimer	--	3,662,000	--	--
Elevated Tripper and Reclaim Tunnel	5,998,000	--	--	--
Subtotal Comparative Cost	7,748,000	5,544,000	8,632,000	9,041,000
Escalation	2,793,000	1,999,000	3,112,000	3,259,000
Escalated Cost	10,541,000	6,543,000	11,744,000	12,300,000
Sales Tax	422,000	302,000	470,000	492,000
Interest During Construction	658,000	471,000	733,000	768,000
Indirect Cost	1,973,000	1,412,000	2,199,000	2,303,000
Total Comparative Capital Cost	13,594,000	9,728,000	15,146,000	15,863,000
Differential Total Comparative Capital Cost	3,866,000	Base	5,418,000	6,135,000

TABLE 3.11-7. COMPARATIVE COSTS--STOCKOUT AND RECLAIM SYSTEM

	Plan A Elevated Tripper $	Plan B Stacker Reclaimer $	Plan C Silo $	Plan D Barn $
Fixed Charge	394,000	Base	553,000	626,000
Energy Cost	109,000	359,000	Base	63,000
Demand Charge	15,000	Base	89,000	23,000
Maintenance	35,000	140,000	Base	65,000
Total Comparative Annual Cost	553,000	499,000	642,000	777,000
Differential Total Comparative Annual Cost	54,000	Base	143,000	278,000

TABLE 3.11-8. COMPARATIVE CAPITAL AND ANNUAL COSTS FOR AUXILIARY BOILERS

Item	Plan A Number 2 Fuel Oil $1,000	Plan B Number 6 Fuel Oil $1,000	Plan C Electrode Boiler $1,000
CAPITAL COSTS			
Auxiliary boiler	Base	Base	110
Exhaust stack	60	60	--
Fuel oil electric heating	--	70	--
Fuel oil pumps and piping	10	10	--
Transformer	--	--	190
Switchgear, breakers, control, and protective relays	Base	Base	25
Electrical bus, cable, and raceway	Base	Base	30
Mechanical construction	10	20	Base
Electrical construction	Base	20	95
General construction	20	24	Base
Total direct costs	100	204	450
Escalation	34	70	154
Escalated subtotal	134	274	604
Sales tax	5	11	24
Interest during construction	11	23	50
Indirect costs	25	51	113
Total comparative costs	175	359	791
Differential comparative capital costs	Base	184	616
ANNUAL COSTS			
Fixed charges	18	37	81
Fuel oil costs	43	29	Base
Energy costs	Base	5	76
Total comprative annual costs	61	71	157
Differential annual costs	Base	10	96

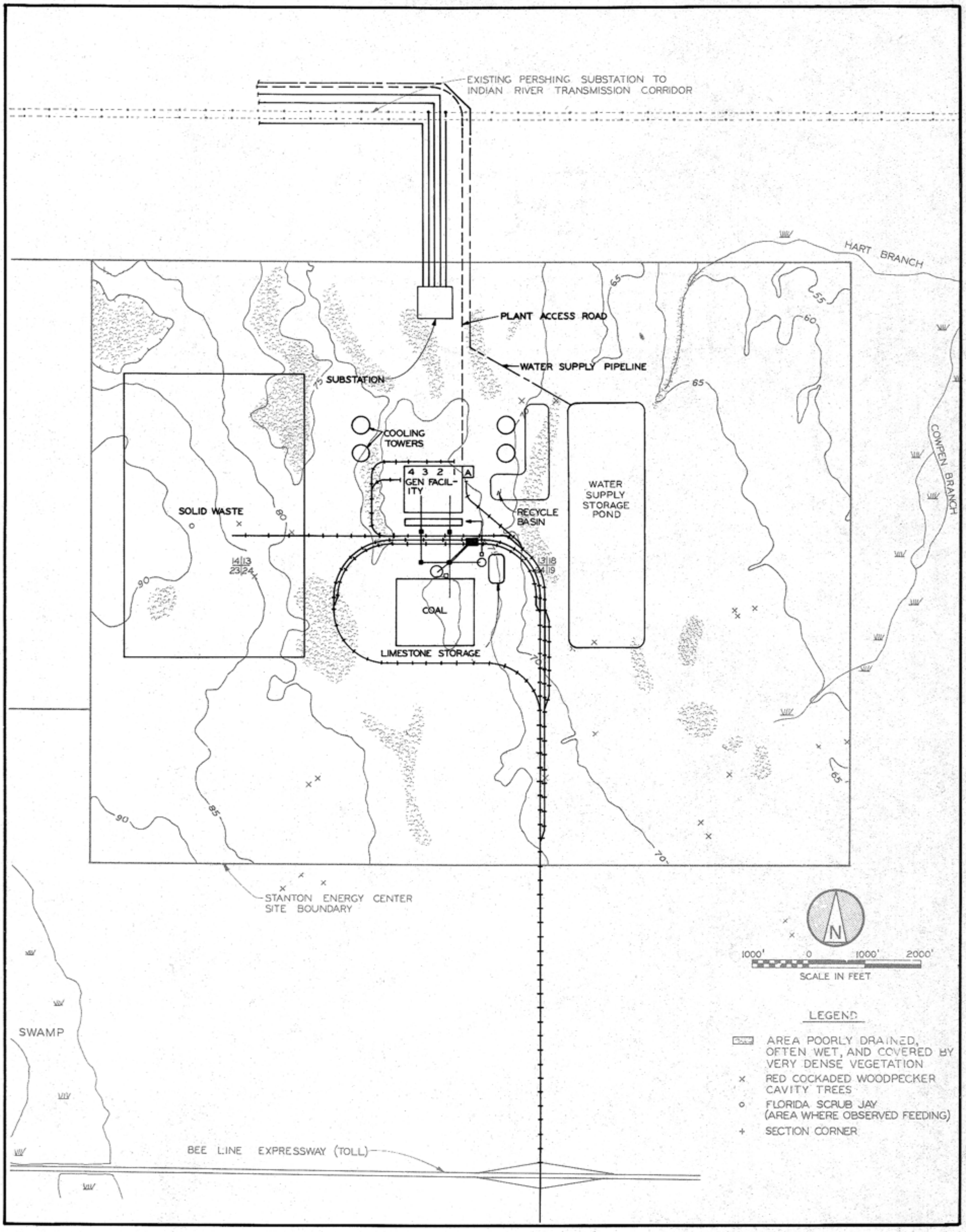

FIGURE 3.11-1. SITE ARRANGEMENT-PLAN A

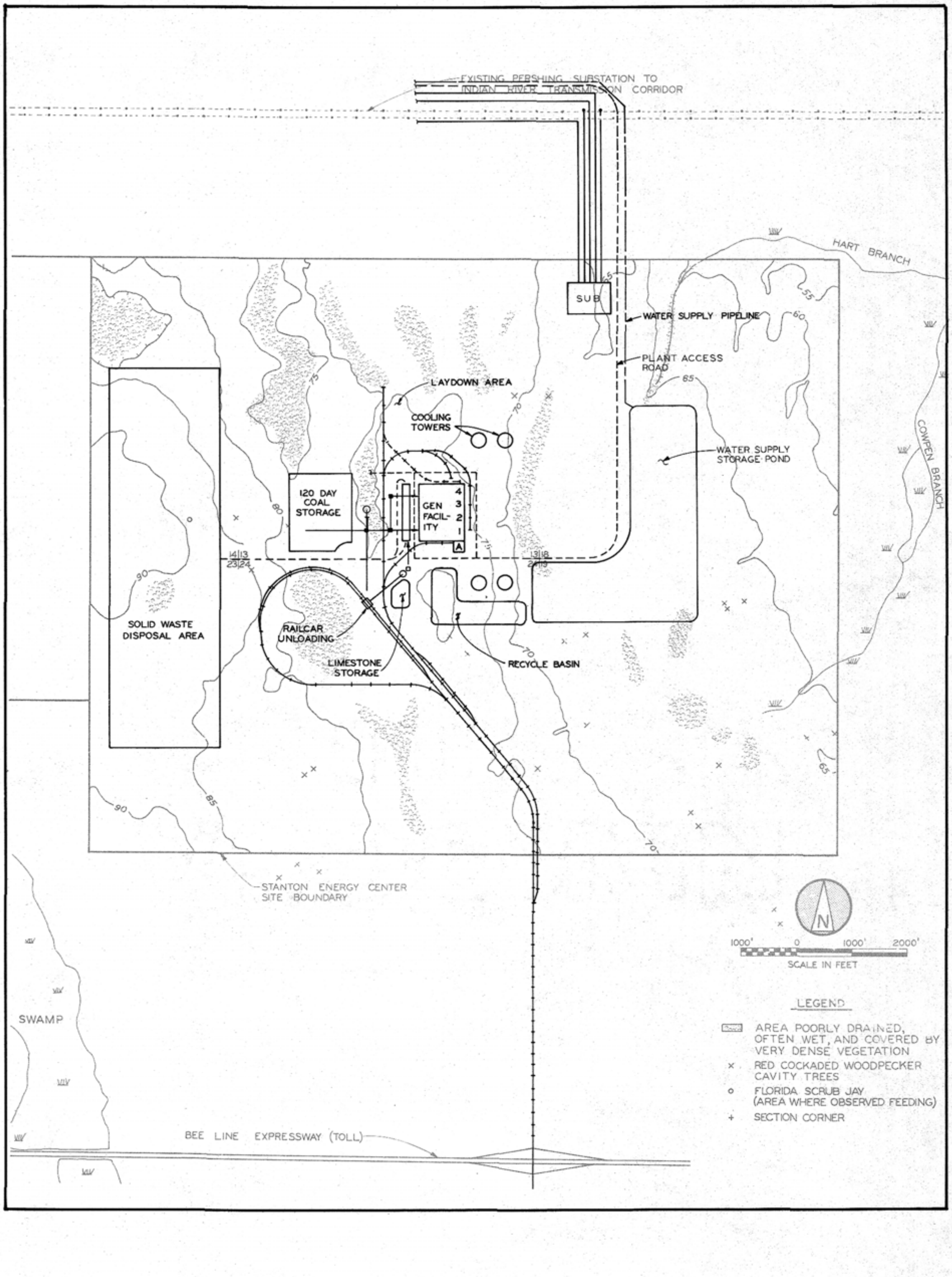

FIGURE 3.11-2. SITE ARRANGEMENT-PLAN B

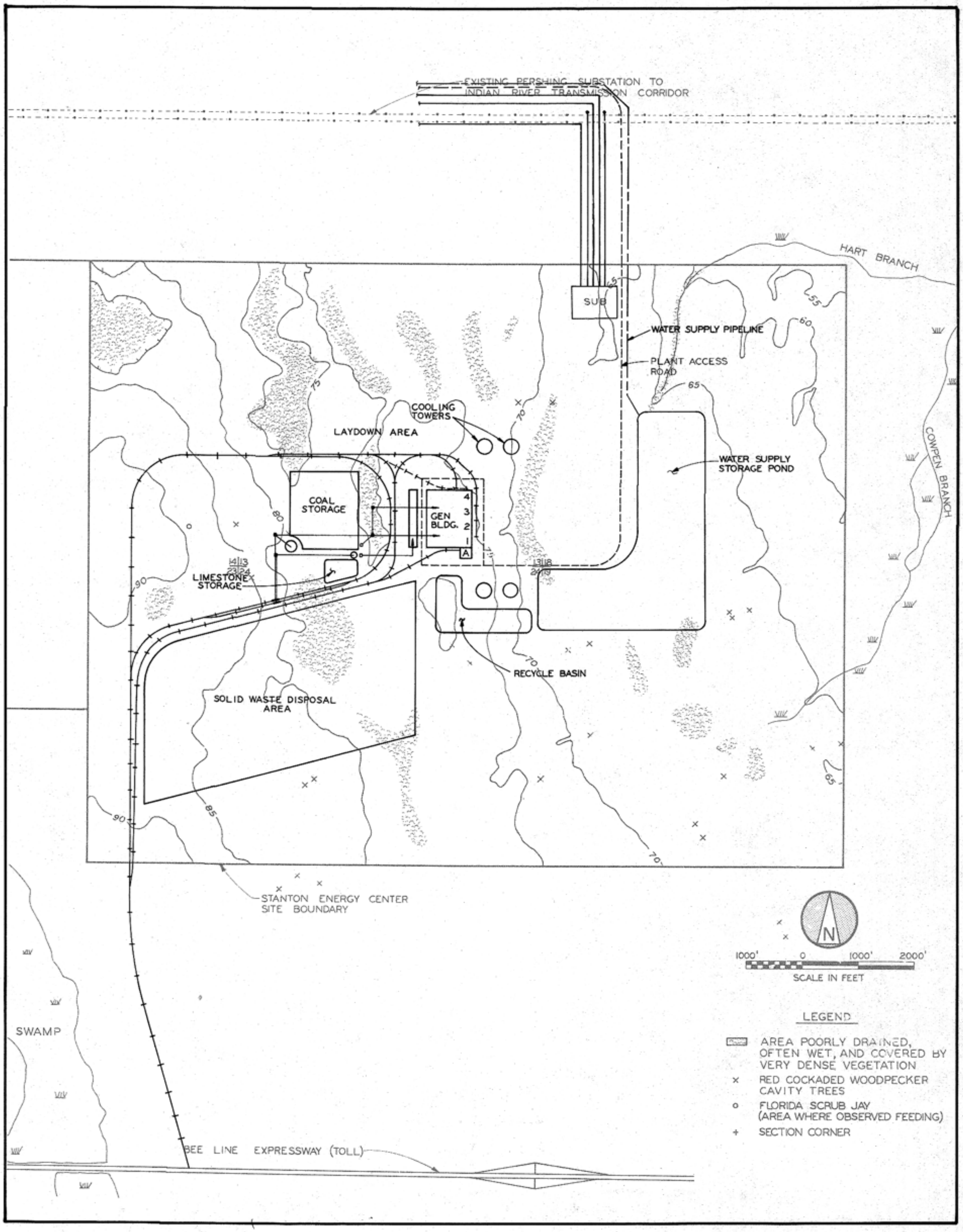

FIGURE 3.11-3. SITE ARRANGEMENT-PLAN C

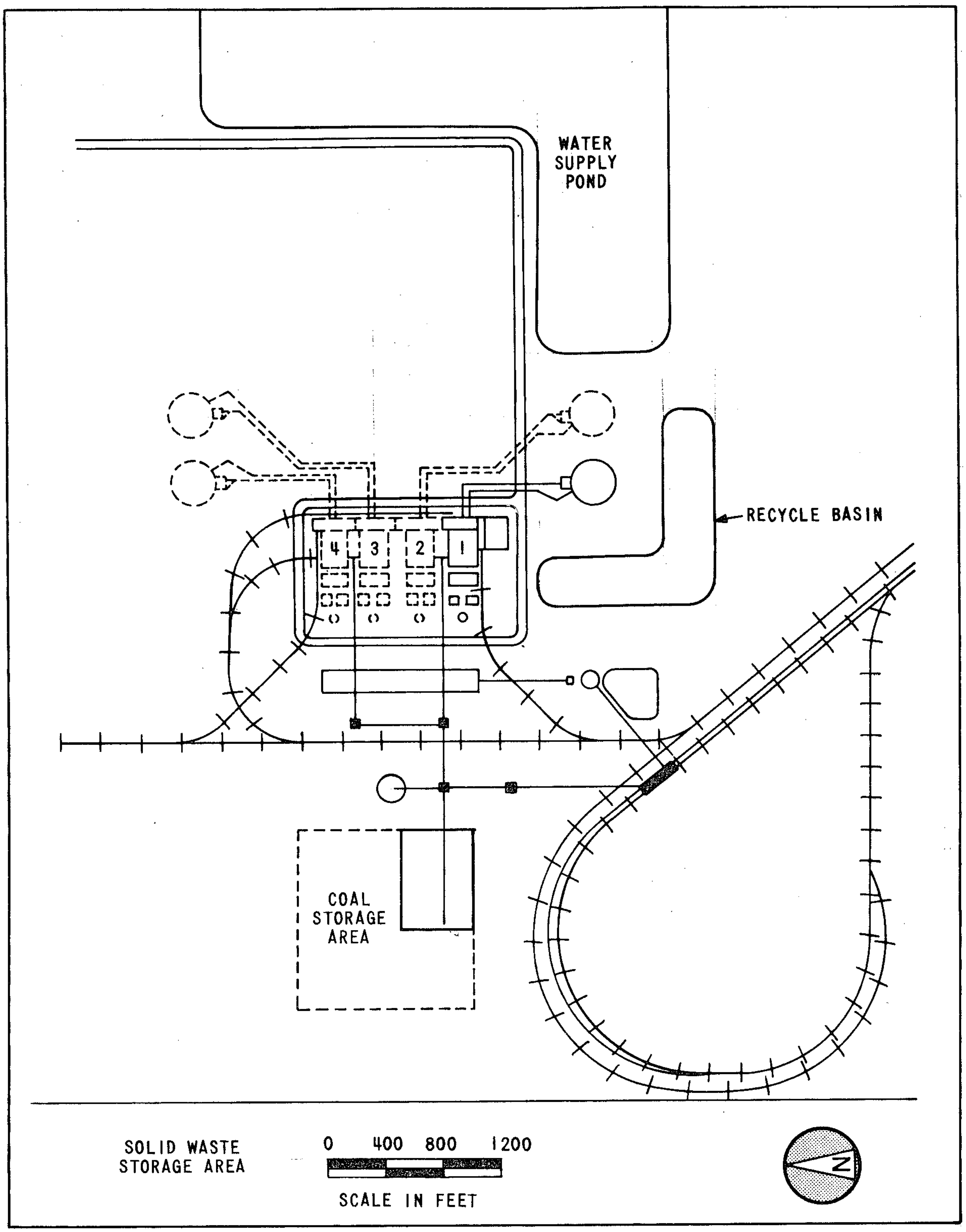

FIGURE 3.11-4. NATURAL DRAFT COOLING TOWER SITE ARRANGEMENT

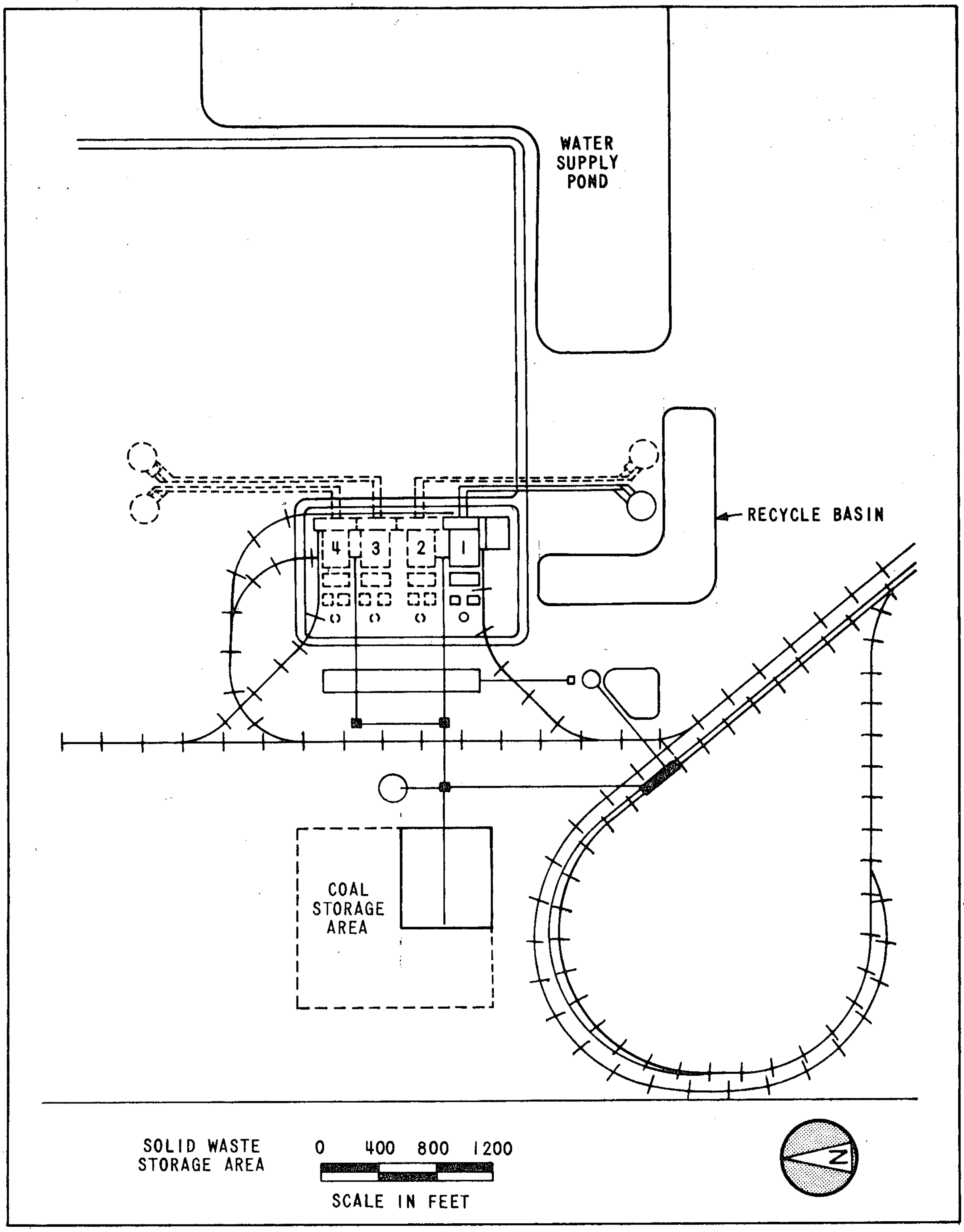

FIGURE 3.11-5. ROUND MECHANICAL DRAFT COOLING TOWER SITE ARRANGEMENT

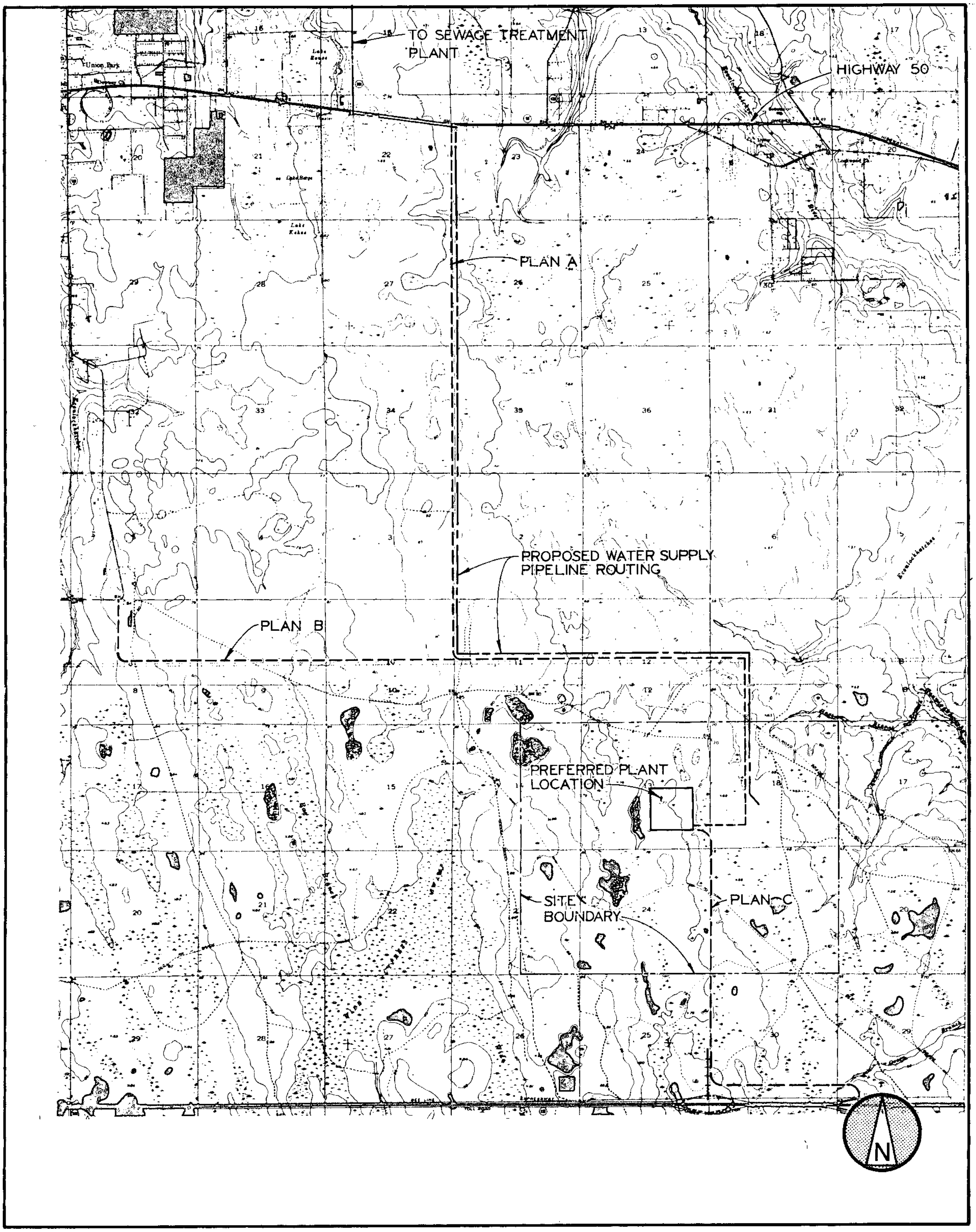

FIGURE 3.11-6. ALTERNATIVE PLANT ACCESS ROADS

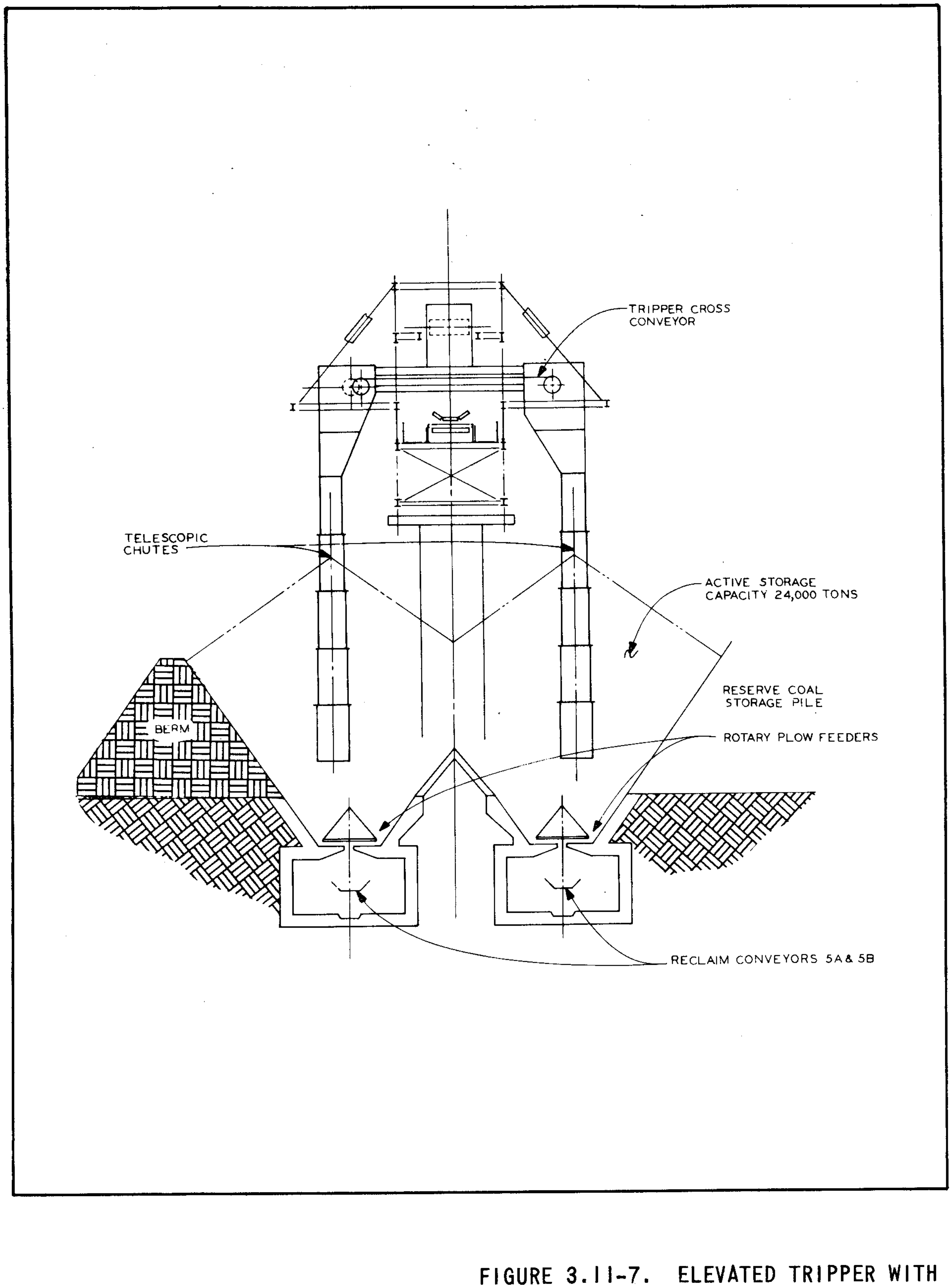

FIGURE 3.11-7. ELEVATED TRIPPER WITH ROTARY PLOW RECLAIM

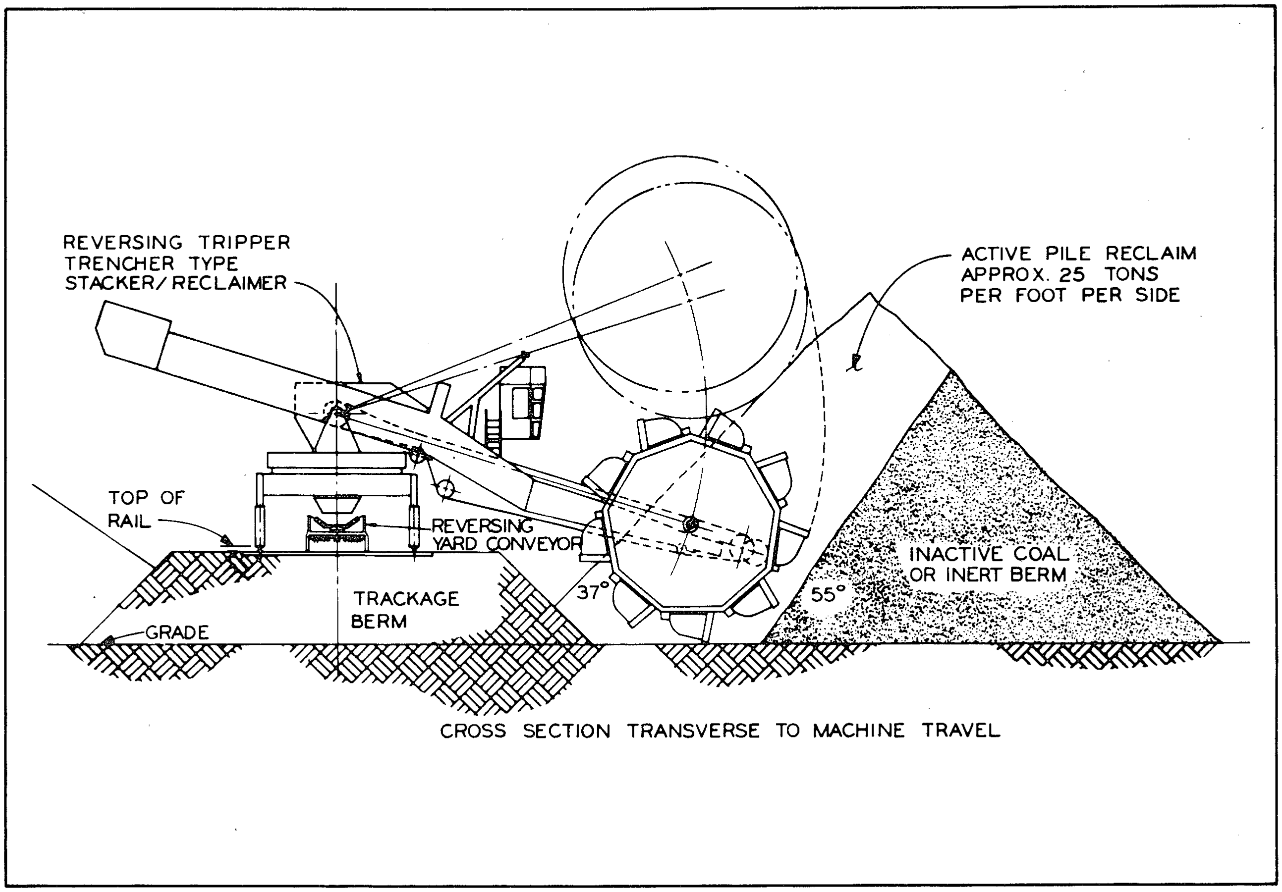

FIGURE 3.11-8. STACKER-RECLAIMER

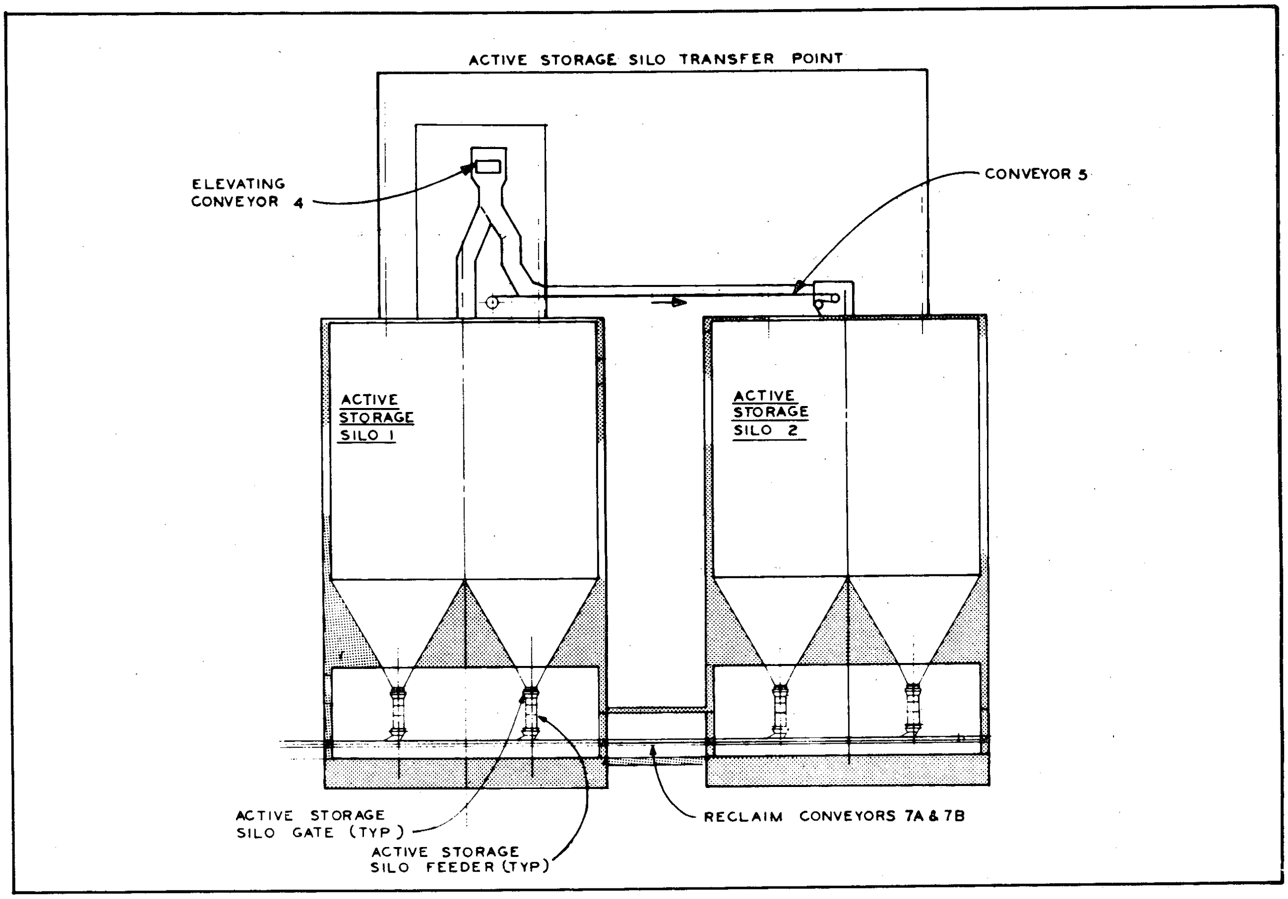

FIGURE 3.11-9. SILO STORAGE WITH VIBRATORY FEEDER RECLAIM

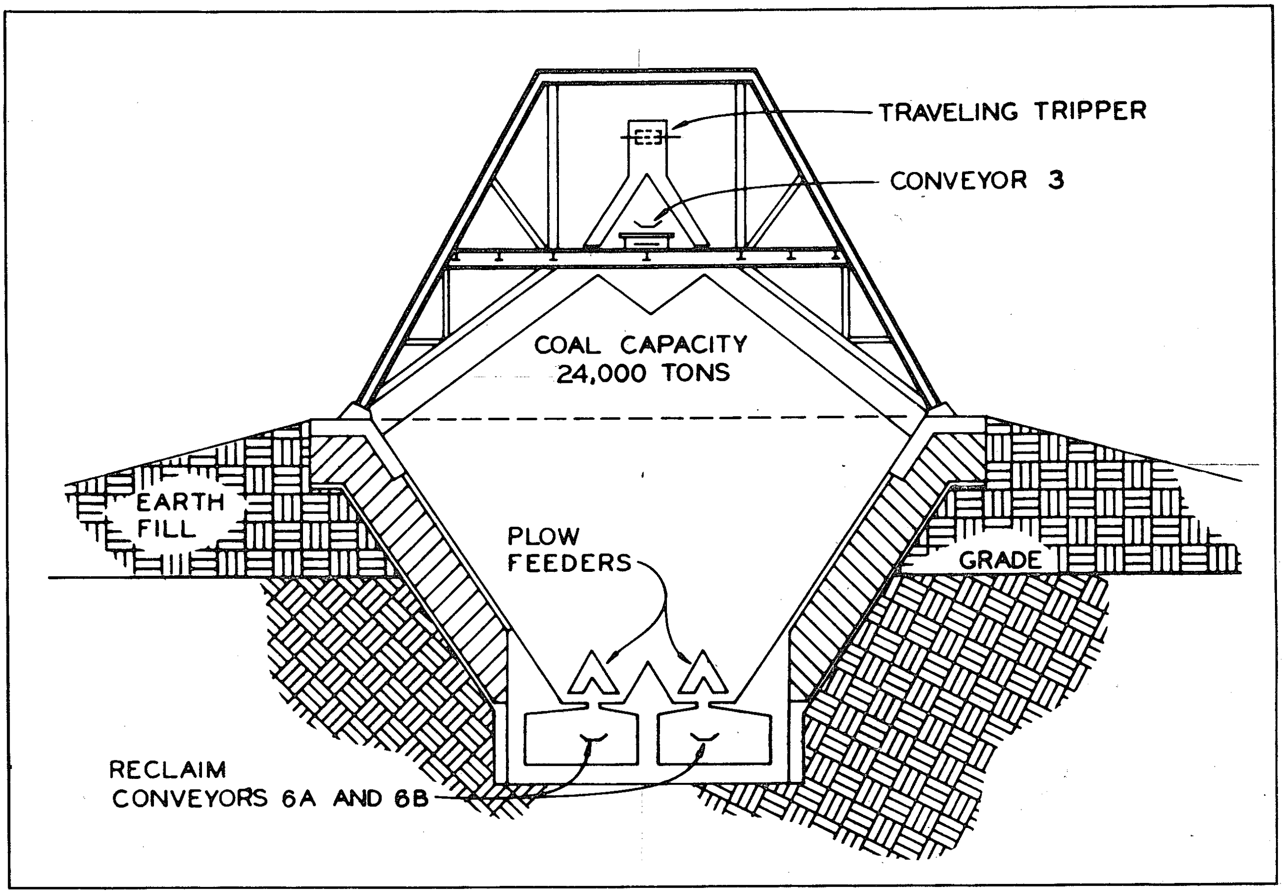

FIGURE 3.11-10. BARN STORAGE WITH ROTARY PLOW FEEDER RECLAIM