Volume 2

INDIANTOWN COGENERATION PROJECT

Site Certification Application

Submitted by Indiantown Cogeneration, L. P.

For Routing To Other Than The Addressee			
To: Clair Fancy		Location:	
To:		Location:	
To:		Location:	
From:		Date:	

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

RECEIVED
APR 22 1992
Division of Air Resources Management

TO: Power Plant Siting Review Committee

FROM: Buck Oven BO

DATE: April 21, 1992

SUBJECT: Modification Request-Indiantown Cogeneration Project, PA 90-41, Module 8041

Attached please find a copy of requested modifications to the Indiantown Cogeneration Project and requested modifications to their Conditions of Certification. Please review the attached material to determine in additional information is required and to determine if the requested modifications would be allowable. Please respond by May 15, 1992.

Attachment:

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

For Routing To Other Than The Addressee	
To:	Location:
To:	Location:
To:	Location:
From:	Date:

Interoffice Memorandum

DATE: April 28,1992

TO: Hamilton Oven

FROM: Clair Fancy

SUBJ: Indiantown Cogeneration Project - Modification request dated 4/20/92

We have reviewed the 4/20/92 proposed modification for the above project and find that there are no adverse impact on air quality. The modifications are discussed below including our comments:

1. **ALTERNATIVE NITROGEN OXIDE CONTROLS**

Using selective Catalytic reduction (SCR) along with wet injection for the control of NOx emissions is satisfactory. The primary concern is that the chosen technology meet the required NOx emission limit specified in PSD-FL-168 specific condition 5 and 6 and the ammonia slip specified in specific condition 7. We also required that the plans and specifications be provided to us in specific condition 6.

2. **USE OF TWO 50% CAPACITY AUXILIARY BOILERS**

Using two auxiliary boilers rated at 50% of the boiler included in the original application and not exceeding the maximum steam input and rated output is satisfactory. Other than allowing two auxiliary boilers instead of one each having 50% of the rated input and output per hour all other requirements would remain the same in specific condition 9.

Based upon the information provided the other modifications do not appear to impact air quality.

Main Boiler Emissions

Pollutant	Basis lb/MMBTU	Emission Limitation lb/hr	TPY
SO2	0.170	582*	2549
NOx	0.170	582*	2549
PM	0.018	61.6	270
PM10	0.018	61.6	270
CO	0.110	376*	1649
VOC at 7% O2	0.0036	12.30	54
H2SO4	0.0004	1.450	6.350
Beryllium	0.00000273	0.0093	0.041
Mercury	0.0000114	0.039	0.172
Lead	0.0000187	0.064	0.280
Fluorides	0.002	7.26	22.26
Arsenic	0.0000511	0.175	0.765

* 24 hour daily block average (midnight to midnight)

For Routing To Other Than The Addressee	
To:	Location:
To:	Location:
To:	Location:
From:	Date:

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

DATE: May 8, 1992

TO: Hamilton Oven

FROM: Clair Fancy CHF

SUBJ: Indiantown Cogeneration Project - Modification request dated 4/20/92

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Based upon the information provided the other modifications do not appear to impact air quality.

CHF/gpk

HOPPING BOYD GREEN & SAMS

ATTORNEYS AND COUNSELORS

123 SOUTH CALHOUN STREET

POST OFFICE BOX 6526

TALLAHASSEE, FLORIDA 32314

(904) 222-7500

FAX (904) 224-8551

MEMORANDUM

RECEIVED
MAY 27 1992
Division of Air
Resources Management

TO: Preston Lewis

FROM: Doug Roberts

RE: Draft Letter on Amendment to Indiantown Cogeneration Project PSD Permit

DATE: May 27, 1992

As we discussed earlier, attached for your review is a draft of a letter requesting an amendment to the above-referenced PSD permit. Also included are the suggested changes to the permit conditions to approve the option to install two auxiliary boilers instead of one, thereby increasing the reliability of the steam supply from that boiler.

I will see you at 2:00 PM to discuss this further. I appreciate your attention to this matter.

DRAFT

//S//

May ___, 1992

Mr. Clair Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399

Re: Indiantown Cogeneration, L.P.
Indiantown Cogeneration Project
PSD-FL-168, Martin County

Dear Mr. Fancy,

On behalf of Indiantown Cogeneration, L.P., I am writing to request that the Department of Environmental Regulation (Department) make certain minor amendments to the above-referenced PSD permit. The Department issued the permit on March 26, 1992. Review of the permit and of the project's design have identified several items in the permit that require change.

During recent final design efforts, ICL has identified a need to provide greater reliability in the operation of the facility's auxiliary boiler. In the original design, a single auxiliary boiler would be used during plant startup and as a backup source of steam to the adjacent citrus plant during those periods when the main boiler was not operating. ICL now proposes that it be permitted to pursue an option to split the auxiliary boiler into two boilers, vented through a common stack, with a total combined capacity equal to the original boiler.

All emission limits and other requirements of the PSD permit for the single auxiliary boiler would be complied with, the only difference being that two 50% capacity boilers may be used, instead of one. The attached analyses show that there are no changes in air quality impacts or the BACT analysis for the auxiliary boiler as a result of this change. A separate request to modify the site certification under the Power Plant Siting Act to allow use of two 50% capacity boilers has been previously filed with the

Department. ICL therefore requests that the PSD permit be amended to reflect that two auxiliary boilers may be used instead of one, subject to the limits already established in the facility's PSD permit. The proposed amendments to the PSD permit to address this revision are attached under the heading "Auxiliary Boiler."

ICL also requests that Specific Condition 2 on page 5 be amended to reflect that propane is permitted to be fired in the main and auxiliary boilers. Propane is referenced elsewhere in the permit as a boiler fuel. Propane should therefore be listed in Specific Condition 2 for clarity. A proposed amendment to that effect is attached.

ICL requests a correction to the PSD permit emission limits for lead. Specific Condition 5 on page 6 of the PSD permit establishes emissions limits for several pollutants, including lead. The hourly and annual lead emission limits and the basis for their calculation as set forth in that condition vary from that requested in the PSD permit application and the limits established in the conditions of certification in the separate Site Certification Order. (Please see attachments.) The difference in these values appears to result from rounding down of the requested basis of 0.0000187 to 0.00001 in calculating the emission rates for lead in the PSD permit. ICL is requesting that the Department amend the PSD permit to reflect the requested emission rates. The amended Specific Condition 5 is attached.

Your attention to this request is appreciated. Please do not hesitate to call me if you or members of your staff have any requests regarding this request.

Sincerely

Douglas S. Roberts

DRAFT

Indiantown Cogeneration Project
PSD-FL-168
Amendments

1. Auxiliary Boiler

Page 1, ¶3, amend as follows:

> The proposed facility includes one main boiler and one steam generator, and one or two auxiliary boilers operated during lightoff and startup of the main boiler or if the main boiler is down and process steam is required for Caulkins Citrus Processing. The primary source of air emissions will be the main boiler, firing coal. Secondary air emission sources include the auxiliary boilers firing natural gas, propane or No. 2 fuel oil, and the material handling systems. The operation of these units will result in significant net emissions increases of regulated air pollutants over the current emissions levels and thus, is subject to review by the Department under the prevention of significant deterioration (PSD) regulations (Rule 17-2.500, Florida Administrative Code).

Page 5, Specific Conditions 3 and 4, amend as follows:

> 3. The maximum heat input to the PC boiler shall not exceed 3422 MMBtu/hr while firing coal. The one or two auxiliary boilers shall not exceed a combined total of 342 MMBtu/hr while firing No. 2 fuel oil and a combined total of 358 MMBtu/hr firing natural gas or propane.
>
> 4. The PC boiler shall be allowed to operate continuously (8760 hrs/yr). The auxiliary boiler or boilers shall operate a maximum of 5000 hrs at the combined total heat input rates with up to 1000 hrs/yr on No. 2 fuel oil with 0.05% sulfur, by weight, and the balance on natural gas or propane. Fuel consumption must be continuously measured and recorded by fuel type (coal, natural gas or No. 2 fuel oil) for both the PC boiler and auxiliary boilers.

Page 7, Specific Condition 9, amend as follows:

9. The auxiliary boiler or auxiliary boilers rated at a combined total of up to 358 MMBtu/hr (Natural gas and propane) and 342 MMBtu/hr (No. 2 fuel oil), shall be limited to a maximum of 5000 hrs/year at the combined total heat input rates with up to 1000 hrs /yr firing No. 2 fuel oil with 0.05% sulfur, by weight, and the balance firing natural gas or propane. The maximum total annual emissions from the auxiliary boiler or boilers will be as follows when firing No. 2 fuel oil for 1000 hrs/yr:

2. Propane

Page 5, Specific Condition 2, amend to read:

2. Only coal, natural gas, propane or No. 2 fuel oil shall be fired in the pulverized coal (PC) boiler and auxiliary boilers.

3. Emission Limits for Lead:

Page 6, Specific Condition 5 amend to read:

5. Based on a permitted heat input rate of 3422 MMBtu/hr, the stack emissions from the main boiler shall not exceed any of the following limitations:

Pollutant	Basis lb/MBtu	Emission lb/hr	Limitation TPY
SO_2	0.170	582*	2549
NO_x	0.170	582*	2549
PM	0.018	61.6	270
PM_{10}	0.018	61.6	270
CO	0.110	376*	1649
VOC	0.0036	12.32	54.0
H_2SO_4	0.0004	1.45	6.51
Beryllium	0.0000027	0.0094	0.041
Mercury	0.0000114	0.039	0.17
~~Lead~~	~~0.00001~~	~~0.034~~	~~0.15~~
Lead	0.0000187	0.064	0.280
Fluorides	0.0015	5.08	22.3
Arsenic	0.000051	0.18	0.77

* 24 hour daily block average (midnight to midnight)

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May 28, 1992

Mr. Clair Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
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All emission limits and other requirements of the PSD permit for the single auxiliary boiler would be complied with, the only difference being that two 50% capacity boilers may be used, instead of one. The attached analyses show that there are no changes in air quality impacts or the BACT analysis for the auxiliary boiler as a result of this change. A separate request to modify the site certification under the Power Plant Siting Act to allow use of two 50% capacity boilers has been previously filed with the Department. I understand the Department concluded the changes would not impact air quality, based on the review of the certification modifications. ICL therefore requests that the PSD permit be amended to reflect that two auxiliary boilers may be used instead of one, subject to the limits already established in the facility's PSD permit. The proposed amendments to the PSD permit to address this revision are attached under the heading "Auxiliary Boiler."

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Your attention to this request is appreciated. Please do not hesitate to call me if you or members of your staff have any requests regarding this request.

Sincerely

Douglas S. Roberts

Douglas S. Roberts

Encls.
cc: Preston Lewis
J. Rogers, SE Dist.
J. Goldman, 1
J. Harper, EPA
C. Shaver, NPS

Indiantown Cogeneration Project
PSD-FL-168
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1. Auxiliary Boiler

Page 1, ¶3, amend as follows:

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* 24 hour daily block average (midnight to midnight)

AIR QUALITY IMPACT INVESTIGATION IN SUPPORT OF THE INDIANTOWN COGENERATION PROJECT DESIGN AND SITE LAYOUT MODIFICATIONS

Proposed Action:

Substitution of Two 50% Auxiliary Boilers for the Original Single Auxiliary Boiler

In order to insure reliability to the steam host, ICL proposes to replace the single auxiliary boiler with two boilers, each one-half the size of the original auxiliary boiler. This substitution will provide a minimum of 50% of the normal steam supply in the event that one of the reduced size boilers is out of service.

Findings:

The modeling methodology employed in the original PSD permit application was used to determine whether air quality impacts caused by the proposed substitution will exceed those presented in the original analysis. SO_2 impacts associated with the operation of the two auxiliary boilers were investigated; one stack for two boilers at full load (i.e., 100% capacity) and one stack for one boiler at full load (i.e., 50 % capacity). Impacts associated with air pollutants, other than SO_2, were estimated by taking the ratio of the specified pollutant emission rate to the SO_2 emission rate.

The GEP stack height for the ICL facility, reported in the original PSD permit application, was calculated at 500 feet. The main boiler stack will be constructed to 495 feet. For the substitution discussed here, the auxiliary boiler stack will be increased from 90 feet to 200 feet. Modeling results based on this substitution, and reflecting the increased auxiliary boiler stack height are summarized in Table 1. Results indicate that the full load case has higher ground-level concentrations than those estimated for the 50% load scenario, over all averaging time periods. The maximum impact areas are within 300 meters of the main boiler stack due to plume downwash conditions created by the boiler building. Modeling results also show that the maximum combined impacts (i.e., main boiler plus auxiliary boiler(s)) are less than the impacts reported in the original PSD application. Similar results are expected for the other air pollutants emitted.

In summary, the substitution of the original auxiliary boiler with two boilers, each one-half the size of the original auxiliary boiler, will result in impacts slightly lower than those presented in the original PSD application. No additional adverse effects to air quality, due to the proposed substitution, are expected.

Proposed Action:

Increased Size of the Coal Storage Building

The original coal storage building was designed to accommodate a seven-day supply of coal. Based on discussions with the coal supplier, ICL has determined that additional coal will be required to be stored on site in order to insure an adequate fuel supply to the facility. ICL has proposed to increase the length of the coal storage building by an additional 150 feet, thereby adding 8000 tons of storage capacity.

Findings:

The increase in length of the coal storage building by 150 feet will not affect either the GEP stack height determination nor the plume downwash calculations, because the controlling structure, which dictates the occurrence and extent of plume downwash, is still the boiler building, as reported in the original PSD application.

In spite of the increase in capacity of the active coal storage pile from 24,000 to 32,000 tons, the daily coal consumption by the ICL facility remains unchanged. Due to the fact that there will be no increase in the number of railroad cars per train load and that the load capacity per car remains unchanged, the number of hours of coal unloading activities per day at the ICL facility is expected to be the same as that reported in the original PSD application. In the original PSD application, the coal unloading activities were very conservatively assumed to occur 4 hours per day on every day of the year. Therefore, no additional fugitive dust impacts associated with this proposed action are expected.

Proposed Action:

Increase in Size of the Ash Storage Silo

In order to accommodate changes to the actual operating practices defined in discussions with the railroad and coal supplier, additional storage capacity is required to provide up to nine days of ash storage on site. This will be accomplished by increasing the ash storage silo diameter from 50 feet to 55 feet and the silo height from 120 feet to 185 feet.

Findings:

The increase of the silo building dimensions will not increase ash emissions at any of the transfer points due to the fact that the daily coal consumption by the ICL facility remains unchanged.

In dispersion modeling, fugitive dust emissions are assumed to be released at ambient temperature with virtually no exit velocity. Therefore, fugitive dust concentration estimates are made with the assumption that there is very little momentum or buoyancy plume rise. By increasing the silo height from 120 feet to 185 feet the fugitive dust emission release will be at a greater height, thereby increasing downwind distance and consequently dispersion of the fugitive dust plume prior to its impact with the ground. Therefore, the fugitive dust concentrations at ground-level receptors, under the same ambient conditions, will be less with an increased release height.

In summary, fugitive dust concentrations around the ICL facility will be slightly less if the release height from the ash storage silo is increased from 120 feet to 185 feet. Therefore, the proposed action will not pose any adverse effects to air quality.

TABLE 1. ICL STACK SOURCES AT MAXIMUM IMPACT LOCATIONS
(AUXILIARY BOILERS AT 100 % LOAD)

Pollutant	Averaging Period	Aux. Boilers	New Total	Original Total
SO_2	3-Hour	17.2 (0.30,050)	23.2 (2.20,310)	24.7 (0.25,100)
	24-Hour	7.5 (0.25,330)	7.5 (0.25,330)	11.6 (0.25,110)
	Annual	0.94 (0.25,340)	0.94 (0.25,340)	1.15 (0.25,100)

(AUXILIARY BOILER AT 50 % LOAD)

Pollutant	Averaging Period	Aux. Boiler	New Total	Original Total
SO_2	3-Hour	6.1 (0.30,030)	22.7 (2.2,310)	24.7 (0.25,100)
	24-Hour	3.9 (0.25,350)	6.0 (3.2,310)	11.6 (0.25,110)
	Annual	0.62 (0.25,340)	0.64 (3.0,310)	1.15 (0.25,100)

Note: Concentrations are in $\mu g/m^3$.
Distance and direction shown are in km and degree, respectively, relative to the ICL main stack in parenthesis.
Total = Main Boiler + Auxiliary Boiler(s)

ENSR
ENSR Consulting and Engineering

MEMORANDUM

TO:	Jean Hopkins/US Generating Co.	DATE:	April 17, 1992
FROM:	Steve Jalinek	FILE:	5402-008-600
RE:	Indiantown Aux Boiler Design Change - Effect on BACT Conclusions	CC:	

Per your request, I have evaluated how changing the auxiliary boiler from a single 100% unit to a set of two 50% capacity units would affect the Indiantown PSD Best Available Control Technology (BACT) Analysis. As we discussed, it's my opinion that given certain design considerations, the BACT conclusions would remain the same if this change were made. This memo discusses these conclusions and the design parameters which must be considered in making the change.

I understand that the auxiliary boiler, originally designed to fire either natural gas, propane, or distillate fuel oil at an output of approximately 358 MMBtu/hr with a total maximum operating schedule of 5,000 hours/yr and a maximum of 1,000 hours/yr on oil, is being redesigned. The new configuration, requested by Caulkins Citrus Processing, will consist of two separate combustion units, each sized for a maximum heat rate of approximately 179 MMBtu/hr and the same operating schedule as proposed in the original application. Both units will exhaust through a common stack.

NO_x Control

The BACT for the original design evaluated the technical and economic feasibility of selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), flue gas recirculation (FGR), and low NO_x burners. These alternative controls are all technically feasible for boilers in either size range (360 or 180 MMBtu/hr). However, SCR, SNCR and FGR were all rejected as BACT for economic reasons, while low NO_x burners with a NO_x emission rate of 0.2 lb/MMBtu was concluded to represent BACT. The DER concurred with this conclusion.

The redesign calls for both boilers, which generally will operate at the same time, to exhaust through a common stack. In this configuration, a common SCR system would be technically feasible and would have essentially identical economic impacts as in the previous design since an equivalent amount of catalyst would be required in either case. However, separate emission control equipment for each boiler would be required for the SNCR, FGR and low NO_x burner alternatives. This would result in slightly higher capital costs for these alternatives for the new design when compared to the costs for the original design. The controlled emissions, however, would remain the same, and thus the economic impact of each alternative would increase. Since the economic impacts for all of these alternatives were concluded to be unreasonable with the original design, the change to two boilers would not alter this conclusion.

Low NO_x burners with a maximum emission rate of 0.2 lb/MMBtu thus would likely still be concluded to represent BACT for the reconfigured auxiliary boiler equipment.

SO_2 and Acid Gas Control

The BACT for the original auxiliary boiler configuration evaluated flue gas desulfurization and fuel sulfur limitations and concluded that limiting the maximum fuel sulfur content to 0.05% was representative of BACT based on unreasonable economic impacts for flue gas desulfurization (FGD). The DER concurred with this conclusion.

As with SCR for NO_x control, the use of two 50% boilers with a common stack would allow the use of a common FGD system. Thus an FGD system for this configuration would have similar capital costs to one designed for a single 100% boiler since the exhaust flows for the two systems would be approximately equal. The emission rates of SO_2 and acid gases would be virtually the same in either case, consequently the cost effectiveness would remain the same and the BACT conclusions would not change. BACT could still be concluded to be represented by low sulfur fuel with a maximum emission rate of 0.052 lb/MMBtu.

CO and VOC Control

The original BACT concluded that combustion controls represented BACT for control of VOC and CO from the auxiliary boiler since the alternative which is generally considered the most stringent, catalytic oxidation, was concluded to be infeasible for an oil-fired source. Oil firing would still be conducted with the new design at the same operating schedule as the original design, thus the technical infeasibility of catalytic oxidation remains unchanged. Were oil firing to be eliminated as an alternative fuel, then the technical arguments against catalytic oxidation would no longer be valid, and the BACT conclusions might change.

However, at this time there is no plan to eliminate fuel oil firing and thus the BACT conclusion of combustion controls for control of CO and VOC remains valid.

Particulate Matter Control

BACT for PM in the original BACT was concluded to be represented by the use of high quality, low ash fuels since fabric filters are infeasible on oil-fired sources and electrostatic precipitators were concluded to be cost ineffective. As discussed, the use of two 50% units firing simultaneously and exiting from a common stack results in a comparable exhaust rate than a single 100% unit. An ESP designed for either configuration would be approximately identical in size and cost, and control the same amount of particulate matter. As a result, the cost effectiveness of this alternative would be identical, and unrepresentative of BACT, for either configuration.

Since neither the fuel mix nor the exhaust rate is changing, the BACT conclusion of 0.02 lb/MMBtu achieved firing low ash fuels, would be concluded to represent BACT for the modified configuration.

Volume 2

INDIANTOWN COGENERATION PROJECT

Site Certification Application

Submitted by
Indiantown Cogeneration, L.P.

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3.4 AIR EMISSIONS AND CONTROLS

3.4.1 AIR EMISSION TYPES AND SOURCES

3.4.1.1 Sources

The primary source of air emissions will be the main boiler, firing coal. There will be one main stack. The stack location has been previously identified in Figure 3.2.04, Emission Point Diagram. The Best Available Control Technology (BACT) for the primary source is addressed in Section 3.4.3.

The ICL project's secondary air emission sources will be as follows:

- Material handling systems
- Auxiliary boiler
- No. 2 fuel tank

The supporting dry bulk material handling systems (coal, lime, and ash) will be sources of fugitive dust. The BACT for these sources is addressed in Section 3.4.3.

The auxiliary boiler will operate normally only during startup of the main boiler or if the main boiler is down and process steam is required for Caulkins Citrus Processing. The auxiliary boiler would rarely operate concurrently with the main boiler under normal load operation. The auxiliary boiler will operate no more than 1,000 hours per year.

The cooling tower will also be a source of emissions. Solids formed in the cooling tower water treatment system can be carried out of the tower in water droplets (drift from the tower) and deposited on the surrounding area.

3.4.1.2 Emissions

The estimated maximum air pollutant emissions from the ICL project represent full load conditions from the boiler and flue gas treatment systems from suppliers currently under consideration. These emission rates are not inclusive of background ambient concentrations introduced into the combustion process. These emissions, as well as the auxiliary boiler emissions, are summarized in Table 3.4.1-1. A comparison of these emission rates with summary of significant emission rate thresholds (as defined in Florida Administrative Code, F.A.C.17-2.310) given in Table 3.4.1-2 demonstrates that the project is subject to Prevention of Significant Deterioration (PSD)/BACT review for sulfur dioxide (SO_2), particulate matter (PM_{10} and TSP), nitrogen dioxide (NO_2), carbon monoxide (CO), volatile organic compounds (VOC) beryllium, inorganic arsenic, and mercury. A complete PSD application is presented in Section 10.1.5.

3.4.1.3 Emissions Inventory

For emissions inventory purposes, DER Form 17-1.202(1), "Application to Operate/ Construct Air Pollution Source," has been completed and is included in Section 10.1.5. These emissions are based on a 100 percent capacity factor.

Table 3.4.1-1
WORST CASE CONTROLLED EMISSION RATES
(Page 1 of 3)

Main Boiler Emissions (tons/year based on 100 percent capacity factor)

	FUEL
POLLUTANT	Coal
Sulfur Dioxide	2549
Particulates	270
Nitrogen Dioxide	2549
Carbon Monoxide	1647
Volatile Organic Compounds[1]	54
Lead	0.28
Beryllium	0.041
Mercury	0.172
Inorganic Arsenic	0.765
Total Fluorides	22.26

[1] No. 2 fuel oil tank will contribute a maximum of 180.6 pounds per year of VOC.

Source: Bechtel, 1990

Table 3.4.1-1
WORST CASE CONTROLLED EMISSION RATES
(Page 2 of 3)

Auxiliary Boiler Emissions (lb/hr)

Basis: One 225,000 lb/hr steam unit

	FUEL	
POLLUTANT	Natural Gas	No. 2 Oil
Sulfur Dioxide	6.16	17.8
Particulates	0.5	1.4
Nitrogen Dioxide	35.8	68.2
Carbon Monoxide	33.6	47.3
Volatile Organic Compounds	1.35	0.63
Lead	Negligible	Negligible

Source: Bechtel, 1990

Table 3.4.1-1
FUGITIVE EMISSION RATES
(Page 3 of 3)

Fugitive Emissions

Source	Control Device	Hours of Operation	Maximum lb/hr
Coal Unloading Area	Fabric Filter	4	0.34
Active Storage Area	Fabric Filter	4	0.696
Coal Reclaim Area	Fabric Filter	8	0.0007
Crusher Tower Area	Fabric Filter	8	0.2887
Silo Bay Area	Fabric Filter	8	0.0010
Ash Silo Area	Fabric Filter	12	0.2088
Ash Recycle Area	Fabric Filter	12	0.0588
Lime Handling Area	Fabric Filter	12	0.0132
Soda Ash Silo Area	Fabric Filter	12	0.0024
Cooling Tower Mist	--	24	43.0*

* Note: This is salt deposition where the other emissions are dust.

Source: Bechtel, 1990

Table 3.4.1-2
SIGNIFICANT EMISSION RATES
(FROM FLORIDA ADMINISTRATIVE CODE)

Pollutant	Rate (tons per year)
Carbon Monoxide	100
Nitrogen Oxides	40
Sulfur Dioxide	40
Particulate Matter (PM)	
TSP	25
PM_{10}	15
VOC	40
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl Chloride	1
Total Fluorides	3
Sulfuric Acid Mist	7
Hydrogen Sulfide	10
Total Reduced Sulfur	10
Reduced Sulfur Compounds	10

Source: 40 CFR 51.24 Prevention of Significant Deterioration of Air Quality and Table 500-2 contained in F.A.C. 17-2500(2)(e)(2).

3.4.2 AIR EMISSION CONTROLS

3.4.2.1 Nitrogen Oxides

Nitrogen oxides (NO_X) will be emitted from both the PC boiler and auxiliary boiler at the ICL facility. As with all combustion sources, NO_X emissions from these two units arise by either the thermal oxidation of nitrogen in the combustion air or the reduction and subsequent oxidation of fuel nitrogen.

Control of NO_X emissions may be accomplished through either minimization of pollutant formation or by flue gas control devices.

PC Boiler

NO_X emissions from the PC boiler will be controlled by combustion controls and selective non-catalytic reduction (SNCR). The SNCR process is based on a gas phase homogeneous reaction, within a specified temperature range, between NO_X in the flue gas and reagent injected into the furnace to produce gaseous nitrogen and water vapor.

One commercially available ammonia-based SNCR process is Thermal DeNO$_X$®, a system patented by Exxon Corporation in 1976. In the Indiantown PC boiler, reagent will be injected into the furnace at a point specifically selected to provide optimum reaction temperature and residence time.

The chemical mechanism of the Thermal DeNO$_X$® process involves at least 31 significant chemical reactions. The main NO_X reduction chemical reaction, which must take place in a temperature range of 1600 to 2200 °F in order to be effective is:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The equipment that would comprise the Thermal $DeNO_X$® system includes the following items:

- Multiple rows of injection headers and nozzles (only one row utilized, but several provided to allow for process modifications required due to furnace temperature profile)

- Necessary piping for delivery of vaporized ammonia, carrier gas, and mixed gas into the injection headers

- Air compressors and reservoir to provide air for carrier gas and ammonia injection requirements (sufficient carrier gas pressure is necessary to achieve uniform distribution of ammonia throughout the combustion zone)

- Aqueous ammonia storage and vaporization facility

- Instrumentation and control system

Use of SNCR will limit NO_X emissions from the PC boiler to 0.17 lb/MMBtu, equivalent to 582 lb/hr at full load.

Auxiliary Boiler

For the auxiliary oil- and natural gas-fired boiler, NO_X emissions will be minimized through the use of combustion controls. Formation of NO_X is a function of excess air level, furnace temperature, and furnace residence time. Combustion controls seek to minimize NO_X formation by adjusting one or more of these variables. The auxiliary boiler will employ low excess air and low NO_X burners to maintain NO_X emissions below 0.2 lb/MMBtu when burning No. 2 fuel oil, which is equivalent to 68 lb/hr at full auxiliary boiler load.

3.4.2.2 Sulfur Dioxide and Acid Gases

PC Boiler

Control of sulfur dioxide (SO_2) and acid gases (H_2SO_4 and HF) in the PC boiler will be accomplished by a lime spray dryer system operating in conjunction with a fabric filter. In the spray dryer, an alkali reagent slurry will be injected into a reaction vessel. The SO_2 and acid gases formed in the combustion process will react with the alkali slurry to form liquid phase salts which are dried to about 1 percent free moisture by heat in the flue gas. Both the dry reaction products and coal fly ash will then be removed from the flue gas by the downstream fabric filter.

This control alternative will achieve a level of SO_2 emission similar to levels achieved with wet scrubbing alternatives, but without generating a wet scrubber sludge. Wet systems typically generate a sludge which contains 10 to 30 percent moisture. Therefore, the waste solids from wet scrubbing must be either handled wet, or dried further to be handled as a dry product. Spray dryer systems generate a product which is dry and, in the case of ICL facility, can be returned by rail with the fly ash to the coal mine for disposal.

Equipment for the spray dryer system will include absorber vessel(s), pebble lime receiving and storage equipment, a lime slaker, lime slurry feed and recirculation tanks, and spent reaction product storage and handling facilities. The SO_2 control system will have a maximum SO_2 emission level of 0.17 lb/MMBtu, which is equivalent to an emission rate of 582 lb/hr at full load.

Auxiliary Boiler SO_2 emissions from the auxiliary boiler will be controlled by burning only low sulfur fuel. Fuel oil will be purchased with a maximum sulfur content of 0.05 percent, which is equivalent to an emission rate of 0.052 lb/MMBtu or 17.8 lb/hr at full auxiliary boiler load. Natural gas is expected to have negligible sulfur content and essentially zero emissions of SO_2 are anticipated during natural gas firing.

3.4.2.3 Particulate Matter and Trace Elements

PC Boiler

Emissions of particulate matter from the PC boiler will be controlled by a fabric filter (baghouse). Furnace flue gas, after passing through the spray dryer, will enter the baghouse at an inlet manifold and gas distributor. Gas will pass through the fabric bags from the inside to the outside; collected particulate will be retained on the inner surface of the bags. When the particulate buildup on the surface of the bags reaches a preset thickness, an automatic, off-line, reverse-air cleaning cycle will be initiated. Collected particulate will drop from the bags into collection hoppers and be conveyed to storage in the ash silo.

Features specified for the ICL facility baghouse system include:

- An air-to-cloth ratio of 2.0 feet/minute with one compartment cleaning and one compartment out of service for cleaning and maintenance (This configuration will minimize baghouse pressure drop and increase bag life.)

- Bypass ducting for boiler startup on fuel oil

- Continuous opacity monitoring

- An independent reverse air cleaning system, including controls, instrumentation, and reverse-air fan

Auxiliary Boiler

Emissions of particulate matter from the auxiliary boiler will be minimized by firing only fuels with low ash content: very low sulfur No. 2 fuel oil and natural gas.

3.4.2.4 Carbon Monoxide and Volatile Organic Compounds

Emissions of carbon monoxide (CO) and volatile organic compounds (VOC) will be minimized in both the PC boiler and the auxiliary boiler by providing conditions in each combustion unit to ensure complete combustion. These will include the use of proper excess air, monitored through advanced combustion controls, and design of the boiler furnace to provide maximum fuel-air mixing and turbulence.

3.4.3 BEST AVAILABLE CONTROL TECHNOLOGY

Best Available Control Technology (BACT) is discussed in detail in the PSD application (10.1.5).

3.4.3.1 Nitrogen Oxides

Formation

Nitrogen Oxides (NO_X) are formed in combustion sources by either the thermal oxidation of nitrogen in the combustion air or the reduction and subsequent oxidation of fuel nitrogen. Virtually all NO_X emissions originate as nitric oxide (NO) as both nitrogen and oxygen dissociate into atomic form at the high temperatures within the boiler and then recombine to form NO. A minor fraction of the NO is further oxidized in the flue gas system to form NO_2. The coal planned for this project will contain some nitrogen compounds, which will primarily be in the form of aromatic nitriles, pyridines, and pyrroles. However, the bulk of the NO_X formation in this facility will be through thermal oxidation of nitrogen from the combustion air, referred to as thermal NO_X.

The rate of formation of thermal NO_X is a function of the residence time, free oxygen, and peak flame temperature. Therefore, most combustion control techniques for thermal NO_X are aimed at minimizing one or more of these variables. Other control methods, known as "tail gas" or "back-end" techniques, remove NO_X from the exhaust gas stream.

Alternative Controls

PC Boiler

The alternative NO_X controls which are applicable to the proposed PC boiler include combustion controls, selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). It should be noted that the latter two alternatives, SNCR and SCR, have not been demonstrated in the United States on a PC boiler firing domestic coals. They have, however, been applied to PC units in Japan and Europe, as detailed further in Section 10.1.5 (PSD Application).

Auxiliary Boiler

NO_X emissions from the oil- and natural gas-fired auxiliary boiler, as with the coal-fired PC boiler, can be controlled either through combustion modifications or add-on technology. Add-on controls include SCR and SNCR; combustion modifications include low excess air (LEA) firing, flue gas recirculation (FGR), and low NO_X burner (LNB) design.

Technical Considerations

For either the PC boiler or the auxiliary boiler, the two most stringent control alternatives are SCR and SNCR. For the auxiliary boiler, flue gas recirculation followed by low NO_X burners are the next most stringent alternatives.

The SCR process involves post-combustion removal of NO_X from the flue gas with a catalytic reactor. Ammonia (NH_3) is injected into the flue gas stream upstream of the catalyst bed, and NO_X and NH_3 combine at the catalyst surface, forming elemental nitrogen and water.

PC Boiler

For the PC boiler, the technical feasibility of applying SCR is questionable, since this alternative has never been demonstrated on domestic coal-fired sources. Although it has been applied to sources firing coal in both Japan and Europe, there are differences in the coals and boiler operating practices between these applications and domestic applications which result in SCR being technically infeasible in this application. There are unresolved technology-related issues relating to the use of this alternative in a US application, including lack of demonstration on pilot-scale units firing US fuels, differences between US and both Japanese and European fuels, as well as differences between the proposed ICL equipment configuration and units where SCR has been applied. These considerations are discussed in detail in Section 10.1.5 (PSD Application).

The SNCR process is based on a gas phase homogeneous reaction, within a specified temperature range, between NO_X in the flue gas and injected reagent to produce gaseous nitrogen and water vapor. As the name implies, SNCR systems do not employ a catalyst, and consequently operate at higher temperatures than SCR systems.

The SNCR process is described in Section 3.4.2.1 and in greater detail in Section 10.1.5 (PSD Application). Technical factors related to application of this technology in the ICL facility include maintaining the appropriate temperature range, minimization of ammonium salt formation, and effect on downstream equipment. Reagent injection nozzles must be situated in locations within the boiler to ensure that the reagent reacts with flue gas at the appropriate temperature. This is best accomplished using multiple injection locations.

Ammonium salts are formed by the reaction of free ammonia with sulfur oxides. These salts tend to condense out of the flue gas at temperatures below 300 °F; in the ICL configuration these salts could plug the boiler, air preheater, and particulate control system. Minimization of ammonia slip (unreacted ammonia) represents the only means to control ammonium salt formation.

Auxiliary Boiler

For the auxiliary boiler, both SCR and SNCR have been applied to domestic sources firing both fuel oil and natural gas. However, for fossil fuel boilers with restricted operating hours, the use of flue gas recirculation or low NO_X burners is more common due to the high cost of add-on controls.

Flue gas recirculation involves extracting a portion of the flue gas from the stack and returning it to the furnace through the burner or windbox. NO_X formation is reduced via a reduction of the peak flame temperature and a lowering of the oxygen concentration in the combustion zone. NO_X reduction potential is directly related to the flue gas recirculation rate. At rates greater than 25 to 30 percent, however, flame stability is compromised and the net thermal output of the combustion source is decreased. Therefore, the tradeoff between lower NO_X emissions and heat output generally limit flue gas recirculation rates to below 25 percent.

In low NO_X burners, NO_X control is accomplished by injecting part of the fuel into the bulk of the combustion air and the remainder of the fuel into primary and secondary combustion zones within the same burner. Thermal NO_X generation in the primary combustion zone is limited in this fuel-lean zone by the reduced peak flame temperature that results. The combustion products from this primary zone (hydrogen, carbon monoxide, and hydrocarbons) are carried into the secondary combustion zone, lowering the local oxygen concentration and reducing the peak flame temperature in this zone as well. Combustion products from the primary zone also provide reducing agents for NO_X reduction in the secondary zone. Finally, zoned combustion permits complete combustion with lower excess air levels than standard burners, which further enhances NO_X emission reductions.

__Economic Considerations__

PC Boiler

Capital and annual operating costs associated with operation of an SCR system and an SNCR system on the PC boiler were estimated from vendor information. These costs are presented in the cost format outlined in the EPA 1990 edition of the Office of Air Quality Planning and Standards "Control Cost Manual" in Tables 3.4.3-1 and 3.4.3-2. Since neither system has ever been installed on a PC boiler firing US coals, system designs have to be conservative and contain sufficient contingency to account for indeterminant process variables, including catalyst life, formation of ammonium salts, and effect on downstream equipment.

Table 3.4.3-1
CAPITAL COSTS FOR NO_x CONTROL ALTERNATIVES - PC BOILER

	SCR	SNCR
Purchased Equipment		
(a) Basic Equipment	9,900,000	3,000,000
(b) Auxiliaries	2,300,000	included
(c) Instrumentation and Controls	990,000	included
(d) Structural Support	990,000	300,000
(e) Freight & Taxes	1,134,000	264,000
Direct Installation	4,594,000	1,069,000
Total Direct Costs (TDC)	$19,908,000	$4,633,000
Indirect Installation		
(a) Engineering & Supervision	1,991,000	463,000
(b) Construction & Field Expense	1,991,000	463,000
(c) Construction Fee	995,000	232,000
(d) Contingencies	3,982,000	927,000
Other Indirect Costs		
(a) Startup & Performance Test	199,000	46,000
(b) Working Capital	241,000	207,000
(c) License Fee	-	1,137,000
Total Indirect Costs (TIC)	$9,399,000	$3,475,000
Total Capital Cost (TCC)	$29,307,000	$8,108,000
Annualized Capital Recovery	$4,757,000	$1,316,000

(ammortized over 10 years
straight line @ 10% interest rate)

Cost Factors: 1990 OAQPS Control Cost Manual

Table 3.4.3-2
ANNUAL COSTS FOR NO_x CONTROL ALTERNATIVES - PC BOILER

	SCR	SNCR
Direct Operating Costs		
Labor		
(a) Operating (8 hours/shift)	$175,200	$175,200
(b) Supervisory	26,000	26,000
Maintenance		
(a) Labor	214,200	214,200
(b) Supplies (50% Maint. Labor)	107,000	107,000
Replacement Parts		
(a) Catalyst	957,000	-
Utilities (2)(3)		
(a) Air	-	-
(b) Steam	47,000	-
(c) Electricity	1,193,000	1,567,000
Raw Materials - Ammonia (2)(3)	248,000	427,000
Catalyst Disposal (2)	13,000	-
Indirect Operating Costs		
Overhead	99,000	99,000
Taxes	293,000	81,000
Insurance	293,000	81,000
Administration	586,000	162,000
Annual Operating Costs	$4,205,400	$2,939,400
Annual Capital and Operating Costs	$8,961,400	$4,255,400
Annual Tons Removed (4)	1,499	1,499
Cost Effectiveness ($/ton)	$5,978	$2,839

Table 3.4.3-2 (Continued)

Notes:
(1) catalyst replacement at 100% in 5 years
(2) per Bechtel Power
(3) based on 100% capacity
(4) based on 0.17 lb/MMBtu emission limit
-compared to boiler emission rate 0.27 lb/MMBtu

Estimated direct costs for the SCR system, including catalyst, catalyst housing, ammonia storage, piping and instrumentation are $19,908,000. Considering installation charges and indirect charges, the total capital cost is estimated at $29,307,000. Annual costs for SCR include operating labor charges (one additional operator/shift), replacement parts including catalyst replacement, additional electrical cost for fan power associated with increased pressure drop due to the catalyst, ammonia cost, catalyst disposal cost, and indirect operating costs. Total annualized cost, including capital recovery charges (based on 10 percent interest rate and 10-year equipment life), is estimated at $8,961,400.

Estimated direct costs for SNCR, including injection nozzles, reagent storage and vaporization equipment, piping, and instrumentation are $4,663,000. Considering installation charges and indirect charges, the total capital cost is estimated at $8,108,000. Annual costs for SNCR include operating labor charges (one additional operator/shift), additional electrical cost for fan power associated with vaporization and pumping, reagent cost, and indirect operating costs. Total annualized cost is estimated at $4,255,400.

Based on an emission limit of 0.17 lb NO_x/MMBtu, either PC control alternative would control an estimated 1,499 tons of NO_x per year more than the use of combustion controls (at 0.27 lb/MMBtu) alone. Cost effectiveness for SCR is thus estimated to be $5,978/ton of NO_x controlled, which is not considered cost effective. For SNCR, cost effectiveness is estimated at $2,839/ton, which is considered reasonable.

Auxiliary Boiler

SCR, SNCR and FGR capital and annual operating costs for the auxiliary boiler were estimated based on vendor information for a similar project. These costs are presented on Tables 3.4.3-3 and 3.4.3-4. Capital equipment for the SCR and SNCR alternatives would be the same as described above, although the size of the equipment would be reduced compared to the equipment designed for the PC

Table 3.4.3-3
CAPITAL COSTS FOR NO_x CONTROL ALTERNATIVES - AUXILIARY BOILER

	SCR	SNCR	FGR
Purchased Equipment			
(a) Basic Equipment	675,000	470,000	318,000
(b) Auxiliaries	included	included	included
(c) Instrumentation and Controls	68,000	47,000	32,000
(d) Structural Support	68,000	47,000	32,000
(e) Freight & Taxes	65,000	45,000	31,000
Direct Installation	263,000	183,000	124,000
Total Direct Costs (TDC)	$1,139,000	$792,000	$537,000
Indirect Installation			
(a) Engineering & Supervision	114,000	79,000	54,000
(b) Construction & Field Expense	114,000	79,000	54,000
(c) Construction Fee	57,000	40,000	27,000
(d) Contingencies	34,000	24,000	16,000
Other Indirect Costs			
(a) Startup & Performance Test	11,000	8,000	5,000
(b) Working Capital	31,000	26,000	14,000
(c) License Fee	-	175,000	-
Total Indirect Costs (TIC)	$361,000	$431,000	$170,000
Total Capital Cost (TCC)	$1,500,000	$1,223,000	$707,000
Annualized Capital Recovery (ammortized over 10 years straight line @ 10% interest rate)	$243,000	$198,000	$115,000

Cost Factors: 1990 OAQPS Control Cost Manual

Table 3.4.3-4
ANNUAL COSTS FOR NO_x CONTROL ALTERNATIVES - AUXILIARY BOILER

	SCR	SNCR	FGR
Direct Operating Costs			
Labor			
(a) Operating	$87,600	$87,600	-
(b) Supervisory	13,000	13,000	-
Maintenance			
(a) Labor	107,100	107,100	87,600
(b) Supplies (50% Maint. Labor)	54,000	54,000	44,000
Replacement Parts			
(a) Catalyst (1)	41,000	-	-
(b) Equipment	68,000	47,000	32,000
Utilities			
(a) Air	-	-	-
(b) Steam	-	4,000	-
(c) Electricity	7,100	600	4,400
Raw Materials - Ammonia	2,900	2,200	-
Catalyst Disposal	1,300	-	-
Indirect Operating Costs			
Overhead	50,000	50,000	16,000
Taxes	15,000	12,000	7,000
Insurance	15,000	12,000	7,000
Administration	30,000	24,000	14,000
Annual Operating Costs	$492,000	$413,500	$212,000
Annual Capital and Operating Costs	$735,000	$611,500	$327,000
Annual Tons Removed (2)	27.4	20.5	17.1
Cost Effectiveness ($/ton)	$26,864	$29,800	$19,123

Table 3.4.3-4 (Continued)

Notes:
(1) catalyst replacement at 50 percent in 5 years
(2) compared to NSPS 0.2 lb/MMBtU with 1000 annual operating hours

boiler. In addition, a different catalyst would be used for the oil- and gas-fired auxiliary boiler than would be employed for the PC boiler.

Total capital costs for the SCR alternative on the auxiliary boiler are $1,500,000. Based on 1,000 hours/hr annual operation, the annual cost of this alternative is estimated at $735,000/yr. Compared to the NSPS for this size unit, an SCR system designed for 80 percent control would reduce annual NO_X emissions by 27.4 ton/yr for a cost effectiveness in excess of $26,864/ton, which is considered unreasonable and unrepresentative of BACT.

Total capital costs for the SNCR alternative on the auxiliary boiler are estimated at $1,222,000; annual costs are estimated at $611,500/yr. Based on a design control efficiency of 60 percent, this alternative would control 20.5 ton/yr and have a cost effectiveness of $29,800/ton. This is also considered unrepresentative of BACT costs for similar sources.

Capital costs for the FGR alternative, including additional ductwork, recirculation fan, insulation and control instrumentation, are estimated at $707,000. Annual costs are estimated at $327,000/yr with 17.1 ton/yr controlled assuming a reduction efficiency of 50 percent. Cost effectiveness of FGR is thus $19,123/ton; similarly this is considered excessive and unrepresentative of BACT.

There is no adverse economic impact associated with the use of low NO_X burners.

Environmental Considerations

Adverse environmental impacts associated with the use of SCR include disposal of spent catalyst and issues pertaining to emissions of unreacted ammonia. For SNCR, unreacted ammonia emissions are the only significant environmental consideration.

The SCR catalyst material will be subject to loss of activity and poisoning and will need to be periodically replaced. The disposal of spent catalyst, which contains various heavy metals and thus considered to be hazardous waste, is an environmental burden and potential liability. Certain catalyst formations must be washed annually in order to be cleaned and regenerated. Wastewater treatment and/or hazardous waste disposal of the wastewater treatment residues would pose additional adverse economic and environmental impacts with these SCR systems.

In light of the restricted water availability of Florida and stringent wastewater discharge requirements in this area, the generation of large amounts of hazardous wastewater represents a significant adverse impact for this potential application.

Not all the reactant ammonia will be consumed in the NO_x reduction reactions. Emissions of unreacted ammonia (ammonia slip) are thus another adverse environmental consideration in any application of SCR and SNCR. Vendors claim that the design and proper operation of the catalyst reactor will keep ammonia slip to less than 10 ppm. However, catalyst design is governed principally by NO_x removal required and allowable ammonia slip. Therefore, requiring either higher NO_x removal or lower residual ammonia requires greater amounts of catalyst, thereby increasing costs. Consequently, to a certain extent there is a tradeoff between NO_x and ammonia emissions in any application of SCR.

Conclusions

PC Boiler

SCR and SNCR are considered the most stringent NO_x control alternatives. SCR has been applied to commercial scale coal-fired sources in both Japan and Europe after intensive R&D and process development work on laboratory-scale and pilot-scale equipment. In transferring SCR technology from the commercial applications in Japan to European sources, technical problems arose which were not anticipated given the Japanese experience. SCR has never been applied, however, to a commercial-scale unit firing domestic coals, and has never been applied to a commercial PC unit in either Japan or Europe using a baghouse for particulate control. Problems comparable to those encountered in European SCR applications are expected for US applications. However, pilot-scale studies to validate this technology on US coals are in their early stages. Therefore, SCR is not considered technically feasible at the present time, and thus not BACT, for Indiantown. Finally, the imposition of this technology would result in an increase in annual operating costs of $9,806,000/yr, which is also considered unreasonable given the current developmental status of this alternative in the US on coal-fired sources.

SNCR has similarly never been applied on a commercial scale boiler firing domestic coals, and there are technical issues which must be addressed involving minimization of the condensation of ammonium salts, maintenance of system operating temperature during reduced load conditions, and compatibility of the system with downstream air pollution control equipment. The technology is currently in use at domestic coal-fired CFBs, and although these applications may be more favorable for the application of SNCR, the technical issues are considered manageable. Compared to the base case combustion controls, the application of SNCR to Indiantown with an emissions level of 0.17 lb/MMBtu results in an increase in capital and operating costs of $3,369,000 and a cost effectiveness of $2,248/ton of NO_X controlled.

Therefore, based on these technical and economic factors, the use of SNCR is concluded to be representative of BACT for control of NO_X for the PC boiler.

Auxiliary Boiler

For the auxiliary boiler, SCR is considered the most stringent control alternative; however, due to the limited operating hours of this source, this alternative would result in unreasonable annualized costs. SNCR, as the next-most stringent alternative, is similarly concluded to be economically infeasible. FGR would be the third-most stringent alternative; this control method is similarly concluded to be unreasonable based on excessive cost effectiveness.

The use of low NO_X burners, as the next alternative, would not have unreasonable annual economic or energy impacts, and use of this alterative would not result in adverse environmental impacts. It is therefore concluded to represent BACT for control of NO_X from the auxiliary boiler.

3.4.3.2 Sulfur Dioxide and Acid Gases

Formation

Emissions of sulfur oxides (SO_x) and acid gases (H_2SO_4 and HF) are generated in coal-fired sources from the release in the furnace of sulfur and fluorine present in the fuel. Sulfur compounds are formed when the organic and pyritic sulfur is oxidized, forming primarily sulfur dioxide (SO_2) with smaller quantities of sulfur trioxide (SO_3) and sulfates (SO_4). Sulfur trioxide further reacts with water present in the flue gas to form H_2SO_4.

Upon combustion, approximately 98 percent of the sulfur in bituminous coal is emitted as gaseous sulfur oxides. Uncontrolled emissions of SO_2 are thus affected only by the fuel sulfur content and not by the firing mechanism, boiler size, or operation.

Sulfuric acid (H_2SO_4) and hydrogen fluoride (HF) gas emissions are created in coal- and oil-fired combustion sources after sulfur and fluorine are released in the furnace from burning fuel containing trace levels of these elements.

Conversion of fluorine to HF depends on the air/fuel mixing, the combustion temperature, and the presence of other trace elements. The formation and emission of H_2SO_4, however, depends on the quantities of gaseous SO_3 and moisture in the flue gas. SO_3 reacts rapidly with water in the flue gas and stack vapor plume to form H_2SO_4.

The amount of SO_3 present in the flue gas depends on the fuel sulfur content as well as conditions supportive of secondary oxidation of sulfur dioxide to sulfur trioxide. Combustion temperature, alkali component concentration in the fuel, and excess oxygen level are a few of the factors governing SO_2/SO_3 conversion.

Alternative Controls

Control of SO_2 and acid gas emissions is primarily effected by removing these pollutants from the flue gas with either wet or dry scrubbing alternatives. Such systems are generally designed to reduce SO_2 and are referred to as flue gas desulfurization (FGD) devices.

In addition, limiting the fuel sulfur content is an applicable control alternative, particularly for fuel-oil fired sources.

Technical Considerations

PC Boiler

Wet scrubbing is a diffusion process in which pollutants (in the forms of gases or mists) are transferred from the gas stream to the scrubbing liquid under saturated conditions. Wet scrubbing contact devices include spray towers, baffle towers, tray towers, and packed towers.

In dry scrubbing systems, commonly referred to as spray dryers, an alkali reagent slurry is injected into a vessel sized for relatively long residence time. The SO_2 and acid gases react with the slurry to form liquid phase salts which are dried to about 1 percent free moisture by heat in the flue gas.

There are various types of wet FGD alternatives, although the most common in use are the limestone and wet lime processes. Like all wet scrubbing process, both of these processes generate a liquid wastewater effluent; wet scrubbing equipment necessarily includes wastewater treatment and disposal systems in addition to the contact device.

Spray dryers, on the other hand, produce a dry reaction product which is collected in the baghouse filter. SO_2 collection efficiency is enhanced in a dry scrubbing system as the flue gas passes through collected unreacted reagent.

The flue gas emitted from wet scrubbing processes is generally 20 to 40°F cooler than from spray dryers. This causes less plume rise, and hence, increased ground level concentrations (GLC) of all emitted pollutants. These increased concentrations cause potentially greater health risk impacts. Significant corrosion, erosion, and scaling of wet scrubber equipment, piping, pumps, fans, and valves have been reported; thus, wet scrubbers require more frequent repairs, parts replacements, and general maintenance at the expense of high costs and reduced availability.

Spray dryers achieve levels of SO_2 removal that are comparable to levels achieved with wet scrubbing systems. Spray drying technology is less complex mechanically than wet scrubbing systems and does not generate a liquid waste; thus treatment and disposal problems and costs are not incurred. Compared to wet scrubbing, the stack gas is hotter, allowing for better plume dispersion and hence lower ground level concentrations.

Auxiliary Boiler

Control alternatives for the auxiliary boiler include wet scrubbing and fuel sulfur restrictions. According to the BACT/LAER Clearinghouse, dry scrubbing has not been applied to oil-fired sources. Since the use of a baghouse filter is not technically feasible for oil-fired sources (due to the sticky nature of oil particulate) and considering that spray dryers must be used in conjunction with a baghouse filter, the use of spray drying for control of SO_2 and acid gases is considered technically infeasible for the auxiliary boiler.

Economic Considerations

PC Boiler

Both wet scrubbing and spray drying are considered equivalent for the PC boiler in terms of emission level. Therefore, it is the difference in operating cost between the two technologies, rather than the cost effectiveness, which is the key economic issue.

Capital and annual operating cost information for these two control alternatives is shown on Tables 3.4.3-5 and 3.4.3-6, respectively. Limestone scrubbing is considered representative of wet scrubbing SO_2 control technology. The estimated equipment costs for this system, including spray tower, limestone storage, slurry preparation tankage, sludge dewatering and handling equipment, pumps, piping, and instrumentation are $45,490,000. Considering installation charges and indirect charges, the total capital cost is estimated at $67,828,000. Annual costs for wet scrubbing include operating labor charges, replacement parts, electrical cost both for fan power and pumping, limestone cost, sludge disposal cost, and indirect operating costs. Total annualized cost, including capital recovery charges (based on 10 percent interest rate and 10-year equipment life), is estimated at $31,385,000.

Estimated equipment costs for spray drying, including absorber vessels (two in parallel), lime slurry preparation and storage, pumps, piping, dry solids handling and storage, and instrumentation are $21,060,000. Considering installation charges and indirect charges, the total capital cost is estimated at $32,271,000. Annual costs for spray drying include operating labor charges, additional electrical for fan power and associated pumping, lime cost, solids disposal cost, and indirect operating costs. Total annualized cost is estimated at $25,383,000. This represents a cost savings of approximately $6,000,000 compared to the wet scrubbing alternative.

Table 3.4.3-5
CAPITAL COSTS FOR SO_2/ACID GAS CONTROL ALTERNATIVES - PC BOILER

	WET FGD	SPRAY DRYER
Purchased Equipment		
(a) Basic Equipment	27,000,000	12,500,000
(b) Auxiliaries	included	included
(c) Instrumentation and Controls	2,700,000	1,250,000
(d) Structural Support	2,700,000	1,250,000
(e) Freight & Taxes	2,592,000	1,200,000
Direct Installation	10,498,000	4,860,000
Total Direct Costs (TDC)	$45,490,000	$21,060,000
Indirect Installation		
(a) Engineering & Supervision	4,549,000	2,106,000
(b) Construction & Field Expense	4,549,000	2,106,000
(c) Construction Fee	2,275,000	1,053,000
(d) Contingencies	9,098,000	4,212,000
Other Indirect Costs		
(a) Startup & Performance Test	455,000	211,000
(b) Working Capital	1,412,000	1,523,000
Total Indirect Costs (TIC)	$22,338,000	$11,211,000
Total Capital Cost (TCC)	$67,828,000	$32,271,000
Annualized Capital Recovery (ammortized over 10 years straight line @ 10% interest rate)	$11,008,000	$5,238,000

Cost Factors: 1990 OAQPS Control Cost Manual

Table 3.4.3-6
ANNUAL COSTS FOR SO_2/ACID GAS CONTROL ALTERNATIVES - PC BOILER

	WET FGD	SPRAY DRYER
Direct Operating Costs		
Labor		
(a) Operating (1)	$787,000	$524,000
(b) Supervisory	118,000	79,000
Maintenance		
(a) Labor	1,180,500	786,000
(b) Supplies (50% Maint. Labor)	590,000	393,000
Replacement Parts	1,350,000	625,000
Utilities (1)(2)		
(a) Air	-	-
(b) Steam	-	-
(c) Electricity	2,919,000	1,249,000
Raw Materials (1)(2)		
(a) Limestone	3,815,000	-
(b) Lime	-	8,726,000
Solid Disposal (1)(2)	6,421,000	6,150,000
Indirect Operating Costs		
Overhead	484,000	322,000
Taxes	678,000	323,000
Insurance	678,000	323,000
Administration	1,357,000	645,000
Annual Operating Costs	$20,377,500	$20,145,000
Annual Capital and Operating Costs	$31,385,500	$25,383,000

Notes:
(1) per Bechtel Power
(2) based on 100% capacity
(3) compared to uncontrolled, based on 0.17 lb/MMBtu emission limit

As the more economic alternative to achieve the same emission level, the use of spray drying is thus more representative of BACT than wet scrubbing.

Auxiliary Boiler

The cost of installing a sodium-based wet scrubber (the most common wet scrubbing alternative for oil-fired sources), was estimated based on a cost quote for a similar installation. Capital and operating costs for this application are shown on Table 3.4.3-7 and 3.4.3-8, respectively. Total capital costs are estimated at $810,000; total annualized costs (including capital recovery) ~~are estimated~~ at $536,000/yr. Based on a 95 percent control efficiency and 1000 hours/yr of annual operation, this alternative would control 8.4 ton/yr compared to the use of low sulfur fuel for a cost effectiveness of over $63,000/ton controlled. This is considered unreasonable and unrepresentative of BACT.

High expected low

X

There are no adverse economic impacts associated with the use of low sulfur oil.

Environmental Considerations

For wet FGD systems, the most significant adverse environmental impact is that these systems generate a wet sludge which must be disposed of. On other sources where this SO_2 control alternative is utilized, the scrubber sludge is generally disposed of at onsite landfills. This practice, however, is not feasible at the ICL site. For the PC boiler, approximately 100,000 ton/yr of wet sludge would be generated, and this material would have to be sent to an offsite landfill for disposal.

Conclusions

PC Boiler

Both wet FGD and spray drying are proven SO_2 and acid gas control alternatives. Both are capable of meeting an emission limit of 0.17 lb SO_2/MMBtu, which is comparable to the most stringent emission limits among operating PC plants. The

Table 3.4.3-7
CAPITAL COSTS FOR SO_2 CONTROL ALTERNATIVES - AUXILIARY BOILER

	WET FGD
Purchased Equipment	
(a) Basic Equipment	360,000
(b) Auxiliaries	included
(c) Instrumentation and Controls	36,000
(d) Structural Support	36,000
(e) Freight & Taxes	35,000
Direct Installation	140,000
Total Direct Costs (TDC)	$607,000
Indirect Installation	
(a) Engineering & Supervision	61,000
(b) Construction & Field Expense	61,000
(c) Construction Fee	30,000
(d) Contingencies	18,000
Other Indirect Costs	
(a) Startup & Performance Test	6,000
(b) Working Capital	27,000
(c) License Fee	-
Total Indirect Costs (TIC)	$203,000
Total Capital Cost (TCC)	$810,000
Annualized Capital Recovery (ammortized over 10 years straight line @ 10% interest rate)	$131,000

Cost Factors: 1990 OAQPS Control Cost Manual

Table 3.4.3-8
ANNUAL COSTS FOR SO_2 CONTROL ALTERNATIVES - AUXILIARY BOILER

	WET FGD
Direct Operating Costs	
Labor	
(a) Operating	$87,600
(b) Supervisory	13,000
Maintenance	
(a) Labor	107,100
(b) Supplies (50% Maint. Labor)	54,000
Replacement Parts	36,000
Utilities	
(a) Air	-
(b) Steam	2,900
(c) Electricity	20,200
Raw Materials - Sodium Hydroxide	2,300
Waste Disposal	500
Indirect Operating Costs	
Overhead	50,000
Taxes	8,000
Insurance	8,000
Administration	16,000
Annual Operating Costs	$405,600
Annual Capital and Operating Costs	$536,600
Annual Tons Removed (1)	8.4
Cost Effectiveness ($/ton)	$63,523

Notes:
(1) compared to 0.052 lb/MMBtu with 1000 annual operating hours

use of wet scrubbing, however, would require disposal of large quantities of wet sludge in landfills, while the solids generated by the spray dryer will be dry and returned to the coal mine with the fly ash for disposal. Furthermore, the spray dryer is estimated to achieve the same emission rate as the wet scrubber at an annual operating cost saving of nearly $6,000,000. Spray drying at an emission rate of 0.17 lb/MMBtu is thus concluded to be BACT for SO_2 and acid gas control.

Auxiliary Boiler

Alternative controls for this source consist of wet scrubbing and fuel sulfur limitations. The use of wet scrubbing is considered unreasonable economically due to the limited hours of operation. The use of low sulfur fuel, which will limit SO_2 emissions to 8.9 ton/yr from the auxiliary boiler is therefore concluded to represent BACT.

3.4.3.3 <u>Particulate Matter and Trace Elements</u>

Formation

The composition and amount of particulate matter emitted from coal-fired boilers are a function of firing configuration, boiler operation, and coal properties. Particulate matter will be emitted from the proposed pulverized coal boiler as a result of the entrainment of incombustible inert matter (ash), and condensible substances. Since PC systems attain almost complete combustion, very little unburned carbon is emitted as particulate matter.

Emissions of particulate matter in oil-fired boilers result from the ash in the fuel and incomplete fuel combustion. PM emissions vary in oil-fired sources with the sulfur content of the fuel, and are also dependent on boiler load, generally decreasing with decreasing load.

Three regulated trace metals, mercury (Hg), beryllium (Be), and arsenic (As) will potentially be emitted from the proposed ICL PC facility. The quantity and characteristics of these trace pollutant emissions depend on the coal composition, the chemical and physical properties of the trace metals, and performance of the control devices.

Heavy metal emissions from fossil fuel-fired boilers are created as a result of combustion of fuels containing metals. Due to the high temperatures and turbulence in the furnace, metals are released in both a particulate and vapor phase, often as metal oxides, chlorides, and sulfates. Depending on the metal compound involved and its condensation temperature, a vaporized metal begins to condense mostly on the surfaces of the fine solid particles in the flue gas (since that fraction has the greatest surface area) at normal stack temperatures (about 350 °F). Condensation occurs as the flue gases cool in the boiler and especially as condensation temperatures are achieved in a acid gas control device such as a spray dryer absorber.

Alternative Controls

PC Boiler

Alternative PM and trace metal control options for coal-fired boilers and other combustion sources include: electrostatic precipitators (ESPs), baghouse (fabric) filters, and venturi scrubbers. Since the most stringent emission levels listed in the BACT/LAER Clearinghouse are for fabric filters, and since the EPA has determined that the they are superior to ESPs for control of PM_{10}, fabric filters are considered to represent the top technology for control of PM and PM_{10} from the proposed project.

Auxiliary Boiler

The PM and trace metal control alternatives for the auxiliary boiler include using ESPs or firing fuels with low ash contents. Fabric filters are not technically feasible for oil-fired sources due to difficulty in dislodging the ash from the bags once it is collected.

Technical Considerations

PC Boiler

The basic components of a baghouse include a filter medium, in the form of cylindrical bags, a tube sheet to support the bags, a gas-tight enclosure, and a means to dislodge the accumulated dust from the bags. The particulate-laden gas stream enters the baghouse, passes through the bags and is then discharged to the stack. Particulate collection occurs through inertial impaction, diffusion, direct sieving, electrostatic attraction, and gravity settling. The first two mechanisms prevail during the early phases of filtration after the cleaning cycle before a "cake" of collected material has accumulated. Build-up of a cake is desirable, since this cake becomes the filter medium. Eventually the pressure drop across the cake increases and the accumulated material must be removed using one of various cleaning methods (i.e., mechanical shaking, reverse air cleaning, or pulse-jet cleaning). The collected particulate drops by gravity to the collection hoppers and is removed for disposal.

A wide range of actual operating performance has been reported for fabric filters. Some of the differences in design and operation which influence emission rates include fabric leaks, cleaning frequencies and techniques, maintenance quality, fabric type, air-to-cloth ratio, and flue gas characteristics.

The particular fabric selected for a given application is dependent on operating temperature and humidity, flue gas acidity, particulate size distribution, and required bag life. Bag materials may be woven, felted, or textured materials; woven fabric is the most commonly used bag material. For extremely low emission rates, Gore-Tex fabric, a laminated system manufactured by one vendor (W.L. Gore Associates), has been used.

Auxiliary Boiler

ESPs have been employed to remove particulate from oil-fired combustion sources such as the auxiliary boiler planned for Indiantown. A typical ESP consists of an alternating array of negatively-charged wires or grids and positively-grounded collection plates. A high voltage is applied across the negative electrodes and the collection plates which produces an electrostatic field between the two elements. As the particulate-laden gas passes through the space between the elements, the field results in a buildup of electrostatic charge on dust particles, which migrate to the collection plates. Particulate removal is accomplished by rappers that vibrate the collection plates and dislodge the particles, which then drop into collection hoppers.

Energy demand is one of the most significant drawbacks for ESPs. For the auxiliary boiler, roughly 1.85 x 10^6 kWhr of electricity would be required annually.

Economic Considerations

PC Boiler

Budgetary cost estimates for installation of a fabric filter system for the ICL PC boiler were obtained based on data for similar projects, and are shown in Table 3.4.3-9. Basic equipment and auxiliaries for this system include the baghouse, filter bags, dampers, and ductwork. Conventional bags would be capable of achieving and emission limit of 0.018 lb/MMBtu, whereas Gore-Tex bags would be expected to meet a limit of 0.012 lb/MMBtu. Total installed cost of the 0.018 lb/MMBtu alternative is estimated at $20,524,000. At an additional cost of $180 per bag ($270/bag for Gore-Tex versus $90/bag for conventional bags), the 0.012 lb/MMBtu alternative is estimated to have a total capital cost of $22,206,000.

Annualized operating costs for the baghouse systems are shown in Table 3.4.3-10. The conventional bag system is estimated to cost approximately $5,999,000/yr; the additional cost of the Gore-Tex bag system would be approximately $832,000/yr considering increased capital recovery charges and additional cost for replacement of the more expensive bags. The Gore-Tex system would control an additional 90 ton PM/yr compared to the conventional system; however this additional removal is not justifiable at more than $9,244/incremental ton controlled.

Table 3.4.3-9
CAPITAL COSTS FOR PM CONTROL ALTERNATIVES - PC BOILER

	.018 lb/mm Btu	.012 lb/mm Btu
Purchased Equipment		
(a) Primary and Auxiliary	$9,523,000	$9,523,000
(b) Instrumentation & Control	952,000	952,000
(c) Structural Support	952,000	952,000
(d) Freight & Taxes	762,000	762,000
(e) Adder for Gore-tex Bags	-	1,300,000
Total Purchased Equipment Cost	$12,189,000	$13,489,000
Direct Installation	$3,657,000	$3,657,000
Total Direct Costs	$15,846,000	$17,146,000
Indirect Installation		
(a) Engineering & Supervision	$1,585,000	1,715,000
(b) Construction & Field Expense	1,585,000	1,715,000
(c) Construction Fee	792,000	857,000
(d) Contingencies	475,000	514,000
Total Indirect Installation	$4,437,000	4,801,000
Other Indirect Costs		
(a) Startup & Testing	158,000	171,000
(b) Working Capital	83,000	88,000
Total Other Indirect	$241,000	$259,000
Total Indirect Cost	$4,678,000	$5,060,000
Total Capital Costs	$20,524,000	$22,206,000
Capital Recovery Factor	$3,345,000/yr	$3,620,000/yr

Auxiliary Boiler

Basic equipment costs for an ESP sized to control oil-fired particulate matter from the auxiliary boiler were estimated based on vendor data for a similar project. Basic equipment costs, shown in Table 3.4.3-11, are $292,000. The total capital investment is estimated at $918,000.

Annual ESP costs were estimated and are shown in Table 3.4.3-12. These costs are based on 1,000 hr/yr annual operation. The most significant annual cost is for electricity ($131,000/yr). The total annualized cost (including capital recovery) is estimated at $480,000/yr. However, due to the limited operating hours of this source, an ESP would only control 3.5 ton/yr of particulate for a cost effectiveness of over $137,000/ton. This is clearly unreasonable and unrepresentative of BACT.

The use of low ash fuels (natural gas and No. 2 fuel oil), on the other hand, does not result in any adverse economic impacts.

Conclusions

PC Boiler

Baghouse filters represent the most stringent PM/PM_{10} control technique which can be applied to PC boilers. Fabric filters represent a cost effective control technology for the proposed project, with no negative environmental impacts.

Therefore, the use of a baghouse filter to control PM emissions to 0.018 lb/MMBtu is representative of BACT.

Auxiliary Boiler

For the oil- and natural gas-fired auxiliary boiler, an ESP is a technically feasible control alternative; but, given the relatively small number of annual operating hours for this unit, would not be cost effective. As the next most stringent alternative, the use of low ash No. 2 fuel oil and natural gas as fuels in the auxiliary boiler is concluded to be representative of BACT.

Table 3.4.3-10
ANNUAL COSTS FOR PM CONTROL ALTERNATIVES - PC BOILER

	.018 lb/mmBtu	.012 lb/mmBtu
Direct Operating Costs		
Labor		
(a) Operating	$175,000	$175,000
(b) Supervisory	26,000	26,000
Maintenance	$792,000	$875,000
Replacement Parts	@$90 ea 216,000	@270 ea $648,000
Utilities		
(a) Electricity	657,000	657,000
Raw Materials		
(a) Ammonia	0	0
(b) Lime	0	0
(c) Limestone	0	0
Disposal Costs	NA	NA
Indirect Operating Costs		
Overhead	$155,000	$163,000
Property Taxes	158,000	171,000
Insurance	158,000	171,000
Administration	317,000	343,000
Capital Recovery	$3,345,000/yr	3,620,000/yr
Total Annualized Cost	$5,999,000/yr	$6,831,000/yr
Uncontrolled Emission Rate	153,000 t/y	153,000 t/y
Controlled Emission Rate	270 t/y	180 t/y
Tons Controlled	152,730 t/y	90 t/y additional
Cost Effectiveness	$39/ton	$9,244/ton incremental

Table 3.4.3-11
CAPITAL COSTS FOR PM CONTROL ALTERNATIVE - AUXILIARY BOILER

Direct Costs	ESP
Purchased Equipment	
(a) Basic Equipment	$292,000
(b) Auxiliaries	$102,000
(c) Instrumentation	$29,000
(d) Structural Support	$29,000
(e) Tax & Freight	$36,000
Total Purchased Equipment Cost	$488,000
Direct Installation	$146,000
Total Direct Cost (TDC)	$634,000
Indirect Costs	
Indirect Installation	
(a) Engineering Supervision	$63,000
(b) Construction & Field Expenses	$63,000
(c) Construction Fee	$95,000
Total Indirect Installation Cost	$221,000
Other Indirect Costs	
(a) Startup & Performance Tests	$6,000
(b) Working Capital	$8,000
(c) Interest During Construction	$49,000
Total Indirect Costs (TIC)	$63,000
Total Capital Cost (TCC)	$284,000
CRF	$159,000/yr

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Table 3.4.3-12
ANNUAL COSTS FOR PM CONTROL ALTERNATIVE - AUXILIARY BOILER

Direct Operating Costs	ESP
Labor	
(a) Operating	$55,000
(b) Supervisory	$8,000
Maintenance	$32,000
Replacement Parts	$36,000
Utilities	
(a) Electricity	$131,000
(b) Water	$0
(c) Steam	$0
(d) Compressed Air	$0
(e) Fuel	$0
Raw Materials	
(a) Ammonia	$0
(b) Urea	$0
(c) Lime	$0
(d) Sodium hydroxide	$0
(e) Soda Ash	$0
Indirect Operating Costs	
Overhead	$23,000
Property Tax	$9,000
Insurance	$9,000
Administration	$18,000
Capital Recovery	$159,000
Total Annualized Operating Cost	$480,000
tpy removed	3.5
Cost Effectiveness $/ton removed	$137,000

Control of PM emissions is concluded to represent BACT for control of trace metal emissions as well for both the PC boiler and the auxiliary boiler.

3.4.3.4 Carbon Monoxide and Volatile Organic Compounds

Formation

Emissions of carbon monoxide (CO) and volatile organic compounds (VOCs) result from the incomplete combustion of carbon and organic compounds. CO and VOC emissions are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, boiler design, and turbulence.

Alternative Controls

Control of the emissions of CO and VOCs may be effected two ways: (1) combustion modifications to minimize the formation of the pollutants, and (2) flue gas catalytic oxidation of any CO and VOCs formed in the combustion process.

Technical Considerations

Catalytic oxidation has been the control alternative used to obtain the most stringent control level for CO and VOCs from fossil fuel-fired combustion units. The use of this alternative is well established for certain fuels and firing configurations, such as combustion turbines firing natural gas. This alternative has never been applied to a coal-fired unit, however.

An oxidation catalyst vendor (Englehard) was contacted to determine the technical feasibility and economic impacts of installing an oxidation catalyst on a coal-fired boiler. Due to the high particulate loading of the flue gas, trace element concentration, and SO_2 level, the vendor stated that they could not provide a catalyst system for this particular application. The vendor stated that flue gas particulate will plug the catalyst, thereby restricting gas flow, masking the active sites and corroding the catalyst.

The vendor contacted also stated that they have never supplied an oxidation catalyst system for an oil-fired boiler. Although the sulfur, ash, and trace element concentrations in fuel oil are lower than the concentrations in coal, the presence of these constituents in fuel oil results in oxidation catalyst systems being technologically infeasible for the fuel oil-fired auxiliary boiler.

Therefore, the use of catalytic oxidation for control of CO and VOC from the proposed PC and auxiliary boiler is not considered technically feasible.

The next most stringent levels of control of CO and VOCs from fossil fuel-fired boilers have been achieved through the use of combustion controls. In general, a combustion control system seeks to maintain the proper fuel to oxygen ratio to ensure complete combustion of the fuel. Essential requirements are sufficient excess air, thorough mixing of fuel and air, and adequate furnace residence time. Advanced combustion controls accomplish this through the use of one or more of the following operational design features:

- Low excess air
- Staged combustion
- Overfire air

Economic Considerations

There are no adverse economic impacts associated with the use of combustion controls for minimization of CO and VOC emissions from either the PC boiler or the auxiliary boiler. Minimization of emissions of these pollutants represents a maximization of fuel use and therefore boiler thermal efficiency, as well as a requirement in terms of licensability and permitting. Such boiler design considerations are therefore considered standard features of modern fossil fuel combustion units.

Environmental Considerations

There are no adverse environmental considerations in conjunction with the use of combustion controls in either the PC boiler or the auxiliary boiler for minimization of the formation of CO and VOC.

Conclusions

Combustion controls minimize the formation and emission of both CO and VOCs without adverse economic, energy, or environmental impacts. Such controls are the most stringent control alternative which has been demonstrated to be applicable to PC and fuel oil-fired units, and are concluded to be representative of BACT.

3.4.4 DESIGN DATA FOR CONTROL EQUIPMENT

Fuel properties were presented in Section 3.3. Main boiler flue gas data is presented in Table 3.4.4-1. These data are based on estimates derived from recent information provided by boiler and flue gas treatment suppliers.

Emission data for the auxiliary boiler are shown in Table 3.4.4-2.

The boiler will be designed to minimize NO_X formation by the use of combustion controls and low NO_X burners. In addition to the low NO_X burners, reagent will be injected into the boiler per the SNCR process to transform the NO_X to elemental nitrogen and water.

The control equipment for the removal of SO_X and other acid gases is the spray dryer absorber (SDA). The SDA injects a lime slurry into the flue gas stream where it reacts with the pollutants. The reaction of the lime with the pollutants produces a precipitate which falls out of the gas stream at either the SDA hopper or is removed at the baghouse.

A multi-compartmented baghouse is used to remove the fly ash and SDA reaction products that are entrained in the flue gas.

A diagram depicting the air emission control design for the unit is illustrated in Figure 3.4.4-1.

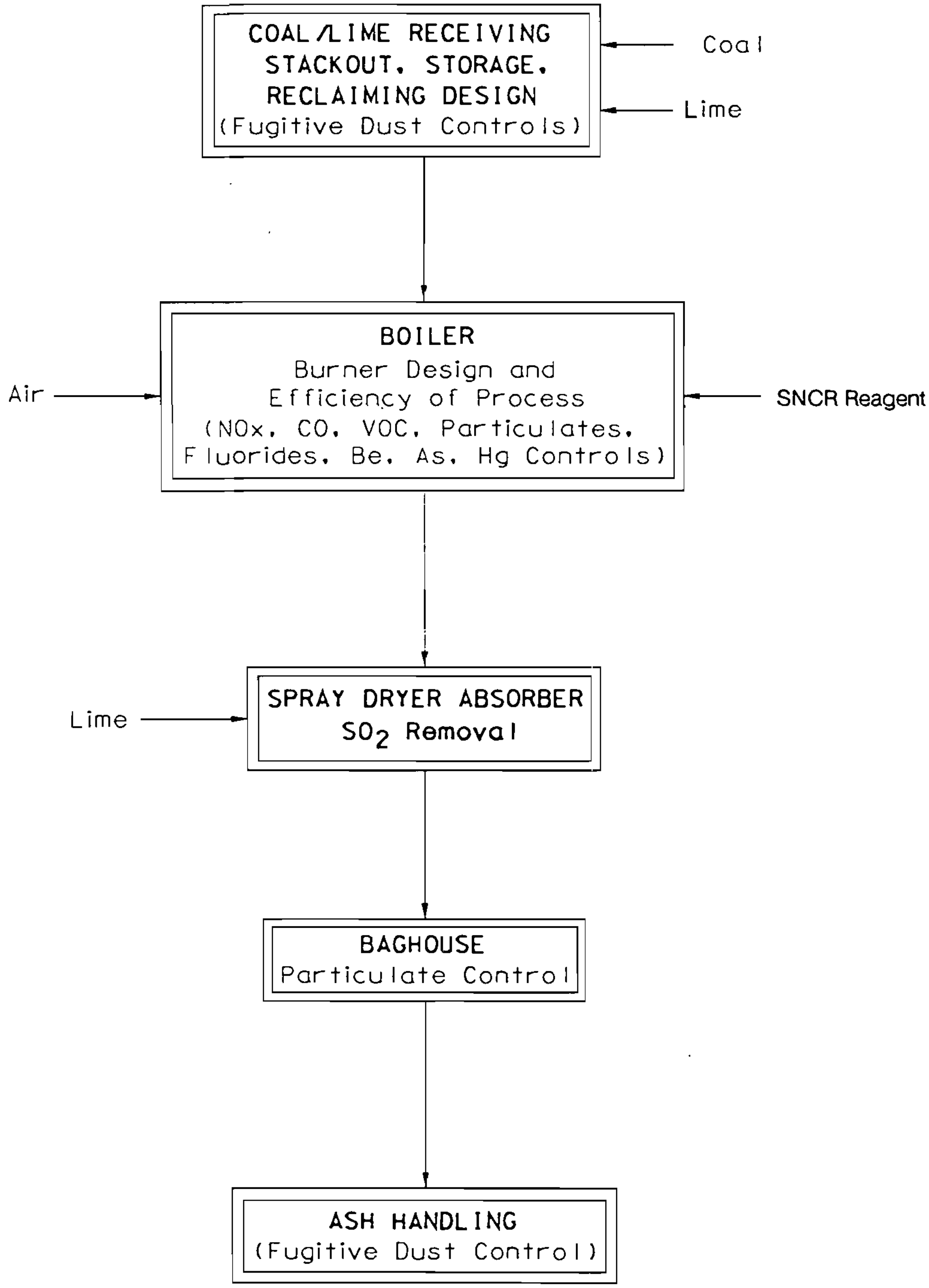


Figure 3.4.4-1.

AIR EMISSIONS CONTROL EQUIPMENT DIAGRAM

Source: Bechtel 1990

INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

Table 3.4.4-1
ESTIMATED PERFORMANCE WITH COAL - FULL LOAD

Conditions	
Ambient Temperature (°F)	80
Relative Humidity (%)	60
Load Condition	Base (Full Load)
Elevation	34 ft NGVD
Emissions	
NO_X (lb/hr)	582
SO_2 (lb/hr)	582
Particulate (lb/hr)	61.6
CO (lb/hr)	376
VOC (lb/hr)	12.3
Exhaust Stack Temperature (°F)	140
Stack Height (ft)	495
Stack Diameter (ft)	16
Stack Gas Exit Velocity (fps)	100

Source: Bechtel, 1990

Table 3.4.4-2
ESTIMATED PERFORMANCE OF AUXILIARY BOILER

Emission Data (auxiliary boiler at 225,000 lb/hr)

	Natural Gas	No. 2 Oil
NO_X (lb/hr)	35.8	68.2
SO_X (lb/hr)	6.16	17.8
CO (lb/hr)	33.6	47.3
VOC (lb/hr)	1.35	0.63
Particulates (lb/hr)	0.5	1.4
Exhaust Stack Temperature (°F)	480	500
Stack Exit Velocity (fps)	102	103
Stack Height (ft)	90	90
Stack Exit Diameter (ft)	5.5	5.5

Source: Bechtel, 1990

3.4.5 DESIGN PHILOSOPHY

The design philosophy used for air emission control systems associated with the ICL project can be summarized as follows:

- Selection of an efficient electrical generating technology
- Selection of clean fuel(s)
- Development of conservative design parameters to envelop emissions obtained from potential pulverized coal fired boilers and flue gas treatment system vendors
- Selection of BACT
- Determination of Good Engineering Practice (GEP) stack height

The ICL project, which includes advanced combustion control, NO_X removal, SO_2 removal systems, and particulate removal, represents an efficient electric generating technology. Thus, by maximizing the power output per unit of fuel consumed, the air pollutant emissions are minimized relative to total power output.

Since a number of boiler and flue gas treatment suppliers are under consideration, the evaluations of the air emission control systems and related emission parameters consider design feature variations and envelop the worst case pollutant emission rates.

The application of top-down BACT (i.e., the evaluation of technical (engineering), economic, and environmental considerations) is used to determine appropriate air emission control technologies. The BACT process results in the selection of control technologies that limit pollution emission rates to levels far below state and federal NSPS. BACT for the ICL project is described in Section 3.4.3.

To prevent excessive ground level pollution concentrations resulting from aerodynamic effects from nearby structures, the ICL project will incorporate GEP guidance in the design of major stacks.

3.5 PROJECT WATER USE

General

The primary source of both cooling and process water for the Indiantown Cogeneration, L.P. (ICL) project is surface water from Taylor Creek/Nubbin Slough (TC/NS). During periods of extended drought when water is not available from TC/NS, cooling water will be withdrawn from the lower production zone of the upper Floridan aquifer and process water will be obtained from a mixture of TC/NS water (from the cooling water storage pond) and groundwater from the upper production zone of the upper Floridan aquifer. The water quality of the TC/NS, and upper and lower production zones of the upper Floridan aquifer are presented in Table 3.5.0-1. Potable water is obtained from the Indiantown Company water service.

The water and wastewater treatment system design incorporates wastewater recycle and reuse to minimize plant makeup water requirements. A sidestream softener is used in conjunction with the cooling tower to allow the cooling tower to operate at higher cycles of concentration. The boiler blowdown is recycled to the cooling tower, rather than being discharged. A portion of the wastewater is reused as dilution water in the spray dryer adsorption system, lowering both the amount of plant makeup water required and the volume of wastewater to be discharged via the injection well.

The availability of makeup water from TC/NS was investigated using a mathematical model developed for this purpose. The model is based on historical flow data and water levels at the S-191 structure on TC/NS. The method of approach, the analysis, and conclusions about water availability are presented in Section 10.9 and summarized in this section.

A summary of maximum daily, maximum monthly, and average annual water requirements from the different water sources is presented in Table 3.5.0-2. The

Table 3.5.0-1
WATER QUALITIES OF THE PLANT WATER SOURCES

Parameter	Taylor Creek/ Nubbin Slough (mg/l)	Upper Floridan Aquifer: Upper Production Zone (mg/l)	Upper Floridan Aquifer: Lower Production Zone (mg/l)
pH	7.1	7.8	7.4
Alkalinity	64	130	138
Total Dissolved Solids	380	2460	4750
Total Hardness (as $CaCO_3$)	130	735	1310
Silica	7.8	17	15.7
Calcium	34	130	233
Magnesium	11	100	177
Sodium	61	600	1198
Potassium	8.1	18	31
Iron	0.50	<0.1	<0.02
Copper	-	<0.01	<0.06
Manganese	-	-	0.24
Sulfate	33	260	423
Chloride	110	1200	2490
Fluoride	-	0.85	1.02
Nitrate	0.46	0.13	-
Phosphate	0.81	0.05	<1.84

NOTES:

1. Concentrations are in mg/l of the ion.
2. Data for Taylor Creek/Nubbin Slough water quality are from the South Florida Water Management District testing from 1980 through 1989.
3. Data for the upper production zone of the upper Floridan aquifer are from test well #LMF-1 located on the adjacent Florida Power & Light, Martin site, July 6, 1990.
4. Data for the lower production zone of the upper Floridan aquifer are from test well #LMF-1 located on the adjacent Florida Power & Light, Martin site, March 1989.

Table 3.5.0-2
SUMMARY OF PROJECT WATER REQUIREMENTS

Case:	Maximum Daily (MGD)	Maximum Monthly (MG/Mo)	Average Annual (MGY)
Primary Source of Water			
Taylor Creek /Nubbin Slough	5.24	152	1740
Backup Sources of Water			
Taylor Creek/ Nubbin Slough (Storage Pond)	0.518	16.0	48.2
Upper Production Zone of the Upper Floridan Aquifer	0.432	13.4	40.2
Lower Production Zone of the Upper Floridan Aquifer	5.76	165	480
Total	6.71	194	568

NOTES:

1. Maximum daily water requirements are based on design flows through the cooling tower and 100 percent load factor for 24 hours.
2. Maximum monthly water requirements are based on the highest average monthly flows through the cooling tower at 100 percent load factor for 31 days.
3. Average annual water requirements for the primary source of water are based on the annual average flows through the cooling tower at 100 percent load factor for 365 days. Average annual water requirements for the backup sources of water are based on the annual average flows through the cooling tower at 100 percent load factor for 3 months.
4. Process water is always based on 100 percent load factor.

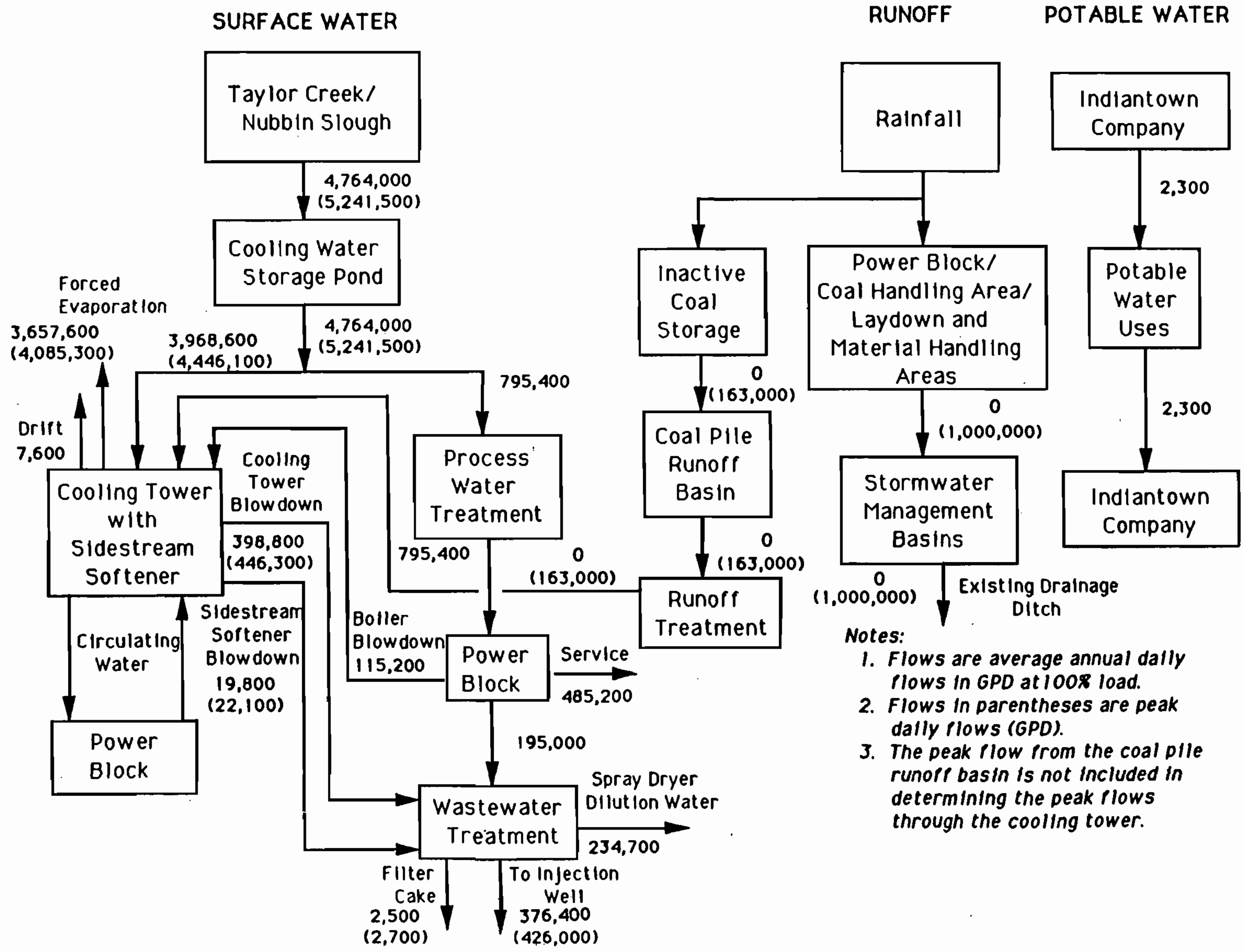
maximum daily requirements are based on the design meteorological conditions for operation of the cooling tower and 100 percent load factor for 24 hours. The maximum monthly requirements are based on the highest average monthly meteorological conditions for the cooling tower (presented in Tables 3.5.1-1 and 3.5.1-2), 100 percent load factor, 24 hours per day for 31 days. The average annual water requirements when using the primary source are based on the average annual meteorological conditions for the cooling tower, 100 percent load factor, 24 hours per day for 365 days. The average annual water requirements when using the backup water sources are based on the average annual meteorological conditions for the cooling tower, 100 percent load factor, 24 hours per day, for 3 months.

The plant consumes water for evaporative cooling in the cooling towers and to meet process water demands such as boiler water makeup, spray dryer lime slaking water, plant service water, etc. Average and maximum water flows for the plant are summarized in the site water budgets for the primary and backup sources of water (Figures 3.5.0-1 and 3.5.0-2). The cooling and process water flows presented are based on the average annual and design meteorological conditions for the cooling tower at 100 percent load factor. The maximum runoff flows are based on a 25-year, 72-hour storm. The potable water flows are based on a plant staff of 65 people per week day distributed over three shifts.

Flows within the water and wastewater treatment system (for both cooling and process water) when using TC/NS as the source of makeup water are presented in Figure 3.5.0-3. The flows are based on average annual conditions for the cooling tower operation at 100 percent load factor. Similarly, Figure 3.5.0-4 presents system flows when using the lower production zone of the upper Floridan aquifer and the mixture of TC/NS from the cooling water storage pond and the upper production zone of the upper Floridan aquifer to meet the plant makeup water requirements.

Figure 3.5.0-1.
SITE WATER BUDGET USING PRIMARY SOURCE OF WATER

Source: Bechtel, 1990



Notes:

1. *Flows are average annual daily flows in GPD at 100% load.*
2. *Flows in parentheses are peak daily flows (GPD).*
3. *The peak flow from the coal pile runoff basin is not included in determining the peak flows through the cooling tower.*

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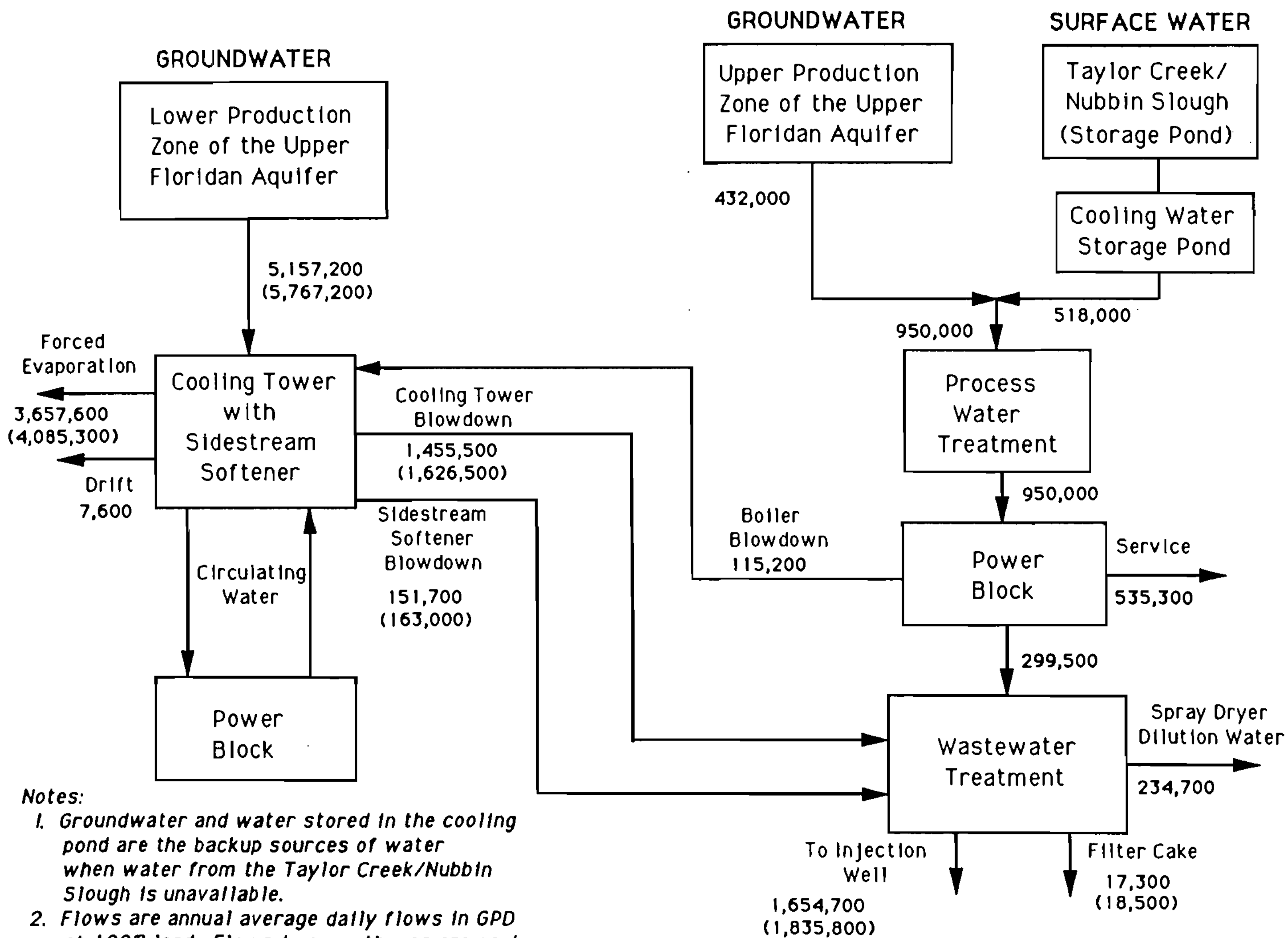
Figure 3.5.0-2.
SITE WATER BUDGET USING BACKUP SOURCE OF WATER

Source: Bechtel, 1990



Notes:

1. *Groundwater and water stored in the cooling pond are the backup sources of water when water from the Taylor Creek/Nubbin Slough is unavailable.*
2. *Flows are annual average daily flows in GPD at 100% load. Flows in parentheses are peak daily flows (GPD)*
3. *Runoff and potable water sources and flows the same as shown in Figure 3.5.0-1.*

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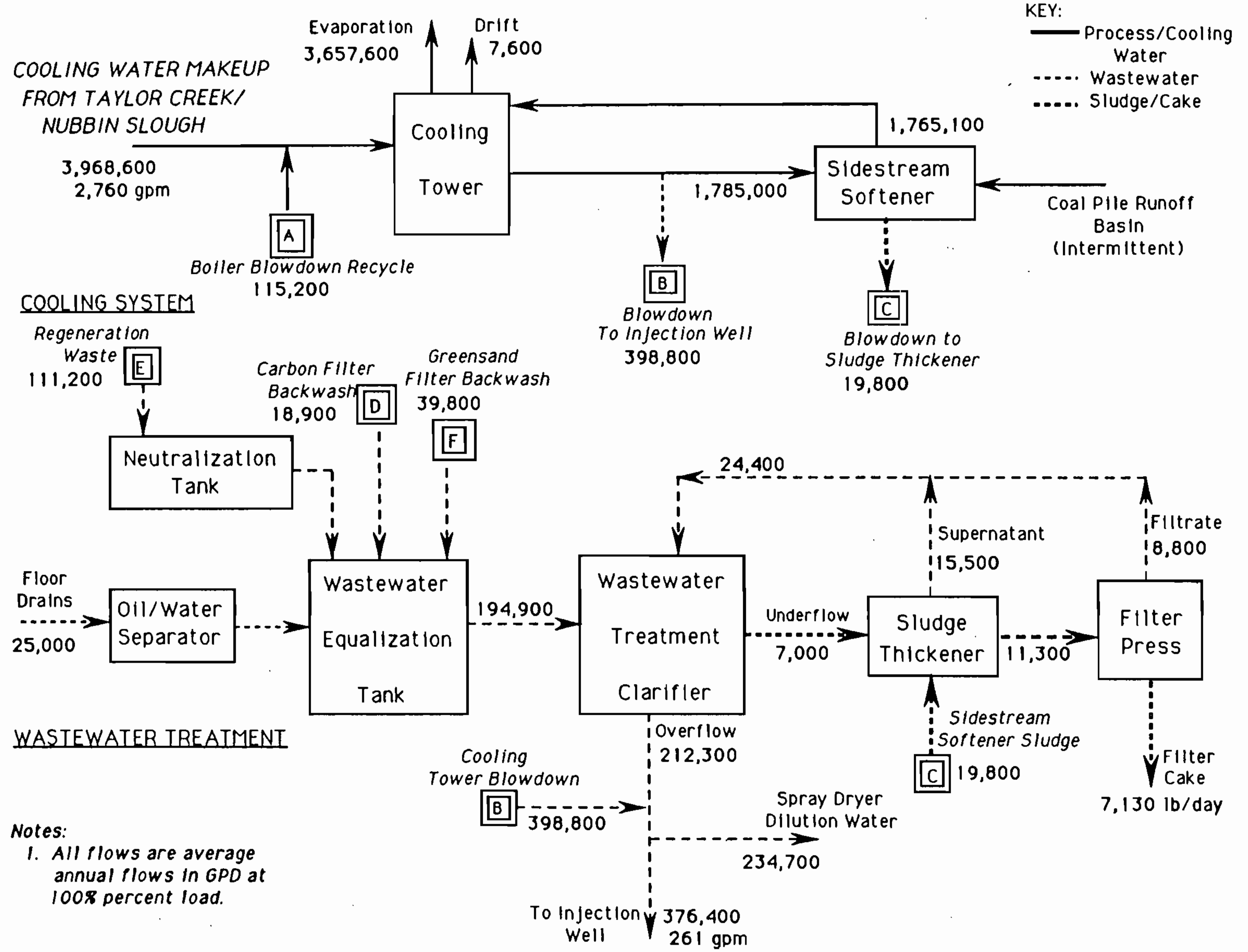

Figure 3.5.0-3. (Sheet 1)
PLANT WATER BALANCE USING PRIMARY SOURCE
OF WATER

Source: Bechtel, 1990

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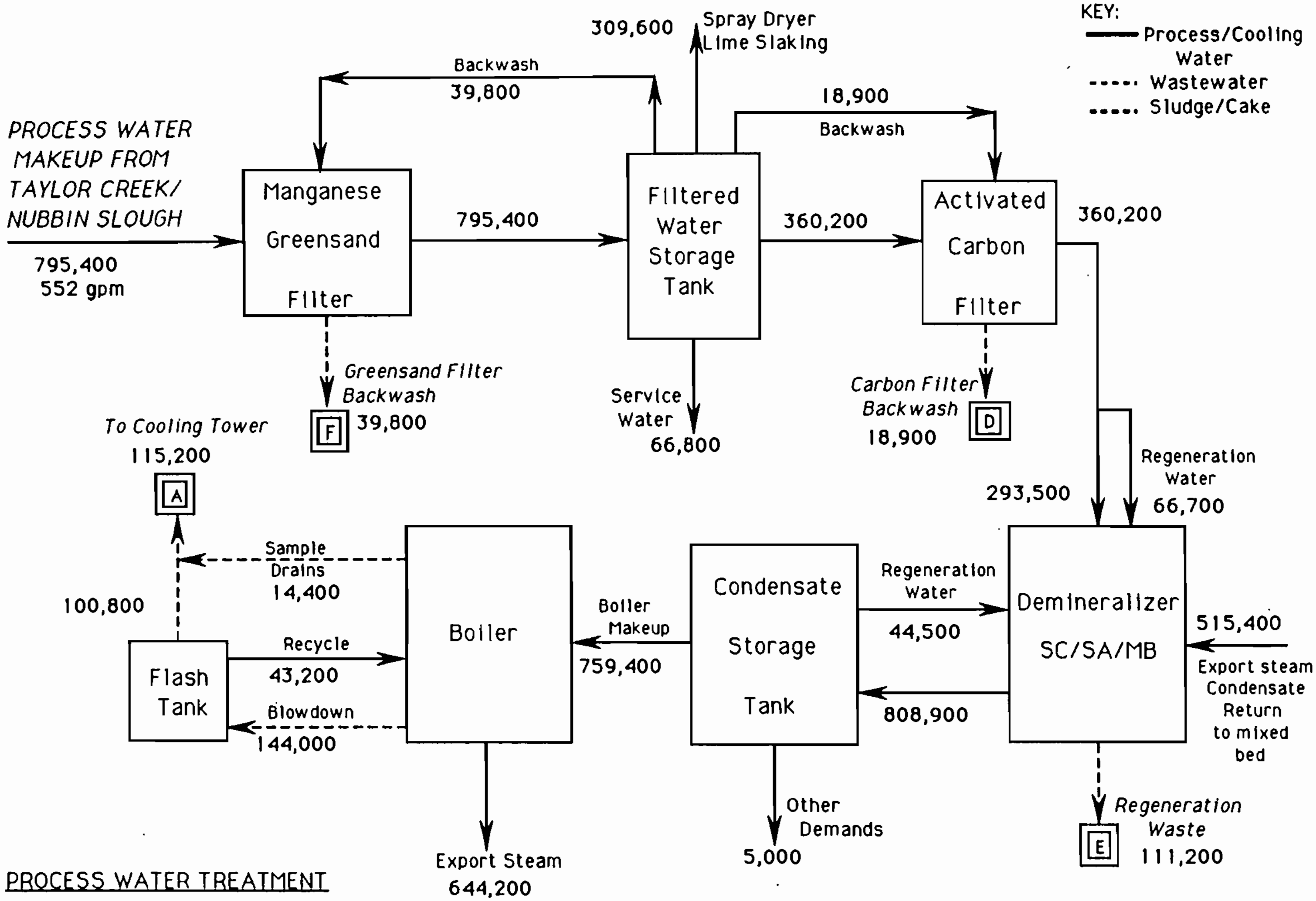
Figure 3.5.0-3. (Sheet 2)
PLANT WATER BALANCE USING PRIMARY SOURCE OF WATER

Source: Bechtel, 1990



PROCESS WATER TREATMENT

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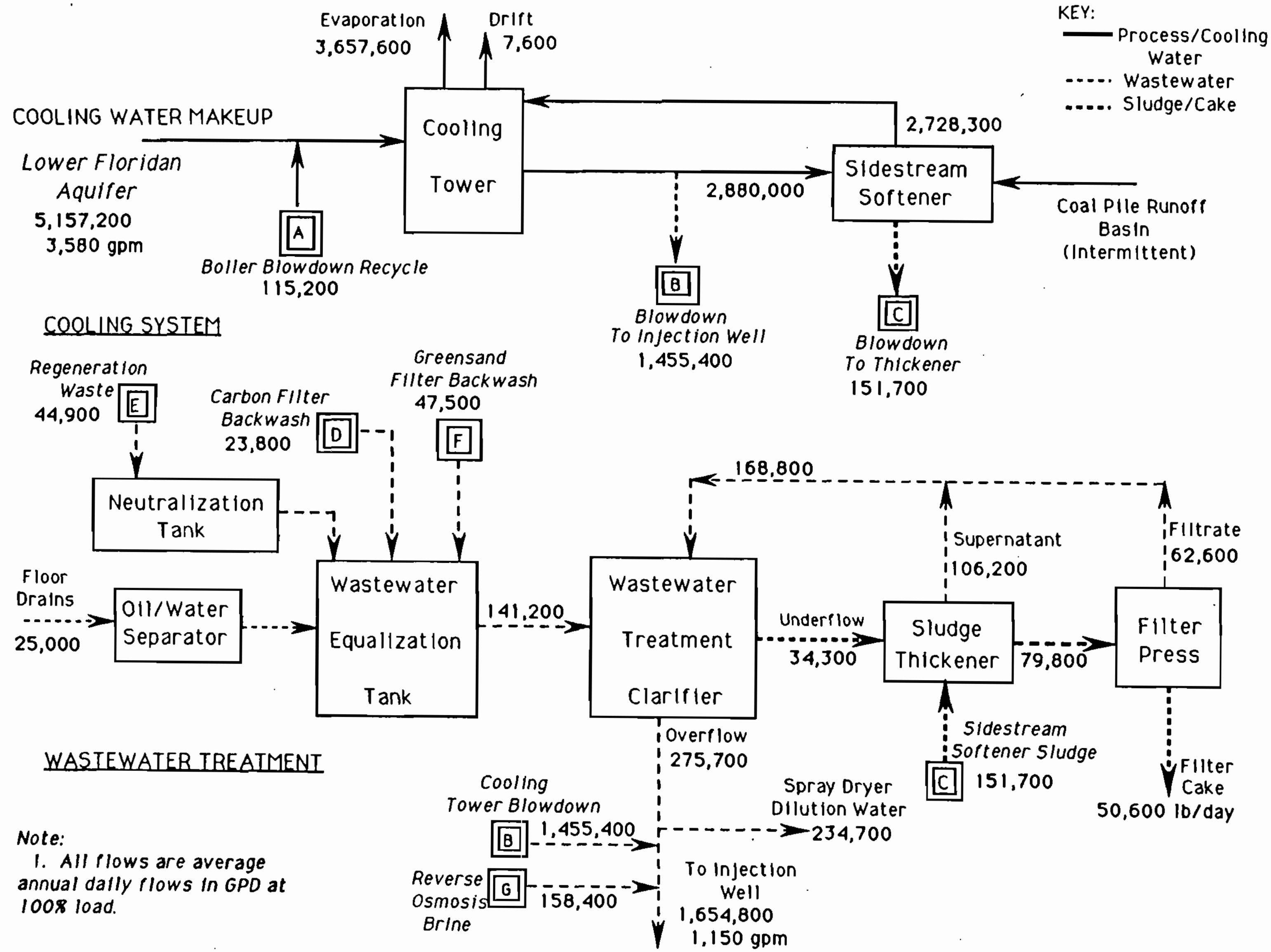

Note:
1. All flows are average annual daily flows in GPD at 100% load.

Figure 3.5.0-4. (Sheet 1)
PLANT WATER BALANCE USING BACKUP SOURCE OF WATER

Source: Bechtel, 1990

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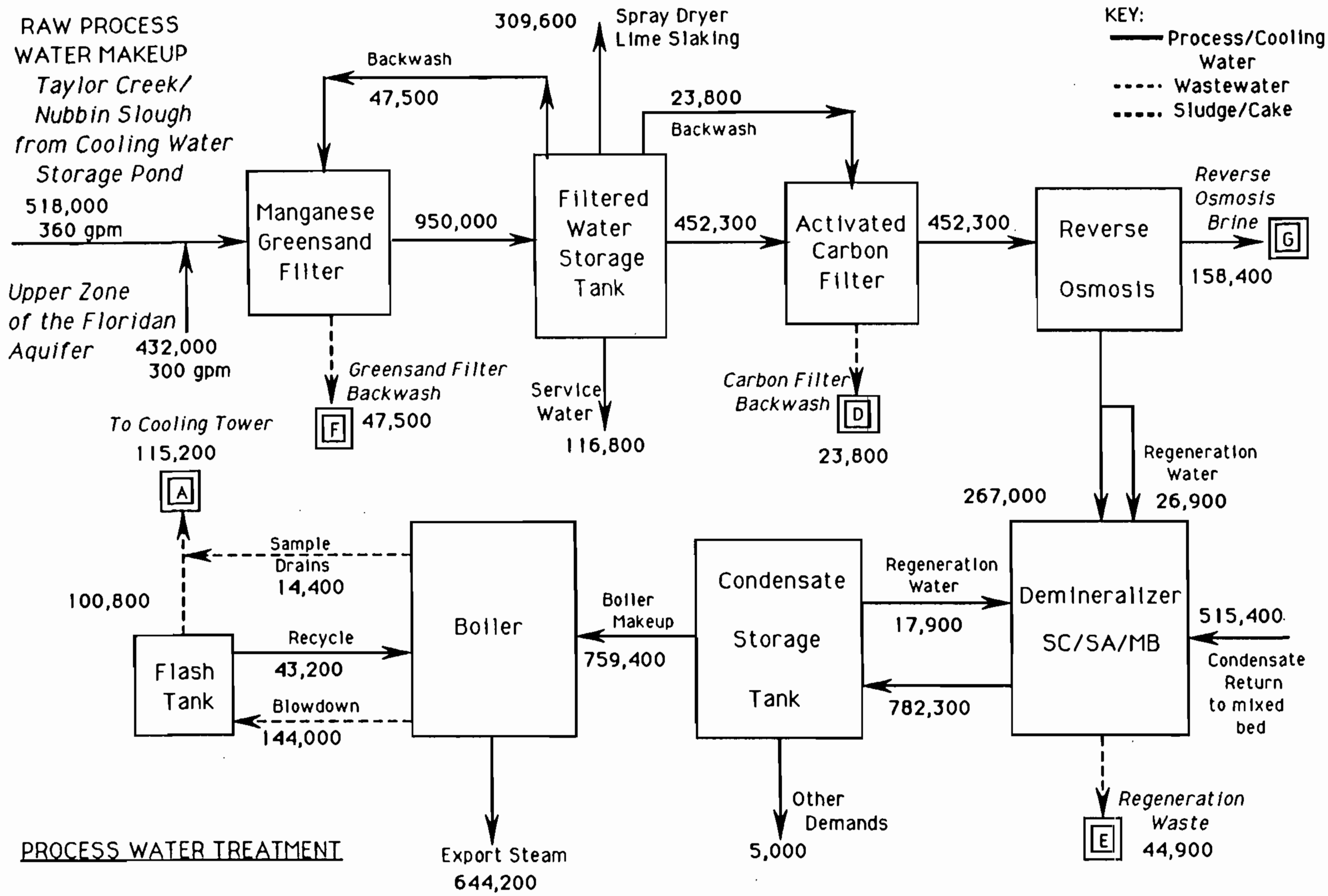

Figure 3.5.0-4. (Sheet 2)
PLANT WATER BALANCE USING BACKUP SOURCE OF WATER

Source: Bechtel, 1990

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Water Availability From Taylor Creek/Nubbin Slough

A water availability study was performed for the ICL project, using TC/NS basin surface runoff flows and Canals C-59, L-635, and L-63N storage. The main objectives of this study were to:

- Determine the availability of the plant water requirement (cooling tower makeup and process water) from TC/NS and the canals for canal water elevations above elevation 16 feet MSL.

- Identify the duration of the time in which withdrawal of plant water is assumed to be unavailable when the water level reaches El. 16 feet MSL.

The historic flow and water elevation data of TC/NS at control structure S-191 were used in this study. The makeup water requirements used in the study do not account for recycle of boiler blowdown to the cooling tower and the water removed with the sludge from the sidestream softener. The net effect is that the demands examined in the study and discussed here are about 2 percent higher than the demands presented in Table 3.5.0-2 and Figure 3.5.0-3. A complete description of the project, plant water requirements, basic data, methodology, assumptions, results, conclusions, and the recommendations is provided in Section 10.9.

Based on the characteristics of the TC/NS watershed and the surface water availability analysis performed, the following conclusions have been made:

1. Procedure of reverse routing, applied in the water availability study to calculate the net inflows, provided a good correlation between historic and predicted water levels and spillway discharges.

2. The average historic flow through the S-191 structure is about 146.4 cfs and average plant water requirements are 7.5 cfs. Therefore, on a mean annual

basis, there is an adequate supply of water. However, due to the rainfall pattern, the supply of water is not distributed evenly, therefore, a storage reservoir is required.

3. The mean annual plant water requirements of 7.5 cfs can be made available from the storage of the canals without lowering the lower level below elevation 16 feet MSL, except during the prolonged drought conditions, which may last a maximum of about 68 consecutive days. However, the total number of days during which the plant water requirements cannot be met in the numerical simulation period of 16 years is only 185 days.

4. During extreme drought months such as May and June of 1981 and 1989, obtaining the plant water requirements from the canals could lower the water level below 16 feet MSL.

5. The maximum drop in the canal water level from the historic water level is 2.5 feet. However, the drop in the adjacent groundwater level will be significantly less as discussed in Section 5.3.1.

6. Changing the criteria of minimum water level from 16 to 17 feet MSL could result in increasing the total number of consecutive days by a maximum of 14 days.

Based on the analysis and the above conclusions, the following features were incorporated into the design of the plant water intake structure described in Section 3.5.1.

1. The pump intake will be located on L-63N near the junction with Canal C-59 due to the water depth and large cross-sectional area.

2. The pump intake will be designed to operate with a minimum water level of 16 feet MSL.

3. To prevent the canal water level from dropping below elevation 16 feet MSL, the pumps' control system will be designed so that during prolonged drought conditions the pumps trip when the canal water level reaches approximately elevation 16.5 feet MSL.

4. Multi-pumps will be installed to facilitate withdrawal rates ranging from average annual flow of 3374 gpm (4.86 mgd) to maximum daily flow of 3642 gpm (5.24 mgd).

5. During prolonged drought in which the canal water level may reach elevation 16 feet MSL, makeup water to the plant will be provided from the Floridan aquifer. The estimated continuous duration of the supply is approximately 90 days.

Discussions with the SFWMD have indicated that the SFWMD prefers a drawdown elevation of 17.5 feet MSL. This was based on the SFWMD review of the water availability study as presented in Section 10.9. ICL will continue to work closely with SFWMD to ensure that their requirements on the drawdown level of the canal will be incorporated into the design of the intake structure and the operation of the facility.

3.5.1 HEAT DISSIPATION SYSTEM

3.5.1.1 System Design

Introduction

A portion of the thermal energy contained in the steam produced by the boiler is converted to electrical energy by the steam turbine generator. However, much of the thermal energy in the steam is absorbed by cooling water flowing through the condenser (circulating water). The heat absorbed by the circulating water is transferred to the atmosphere in a cooling tower. The quantity of heat dissipated in the cooling tower for the ICL plant is about 1.7×10^9 Btu/hr at 100 percent load.

The cooling water system consists of an intake structure, cooling water storage pond, cooling tower, condenser, and sidestream water softener. The location of this equipment on the site is shown in Figure 3.1.1-1. Figures 3.5.0-3 and 3.5.0-4 present the average flows through the cooling water system for the primary and backup water sources, respectively.

Plant Water Intake Structure

The plant makeup water intake structure, to be located on Taylor Creek (L-63N) at the junction with Canal C-59, is designed to provide an average flow rate of 3374 gpm (4.86 MGD) and a maximum flow rate of 3642 gpm (5.24 MGD). The location of the intake is shown on Figure 2.3.4-11.

In addition to the design features presented in Section 3.5, the following factors are also considered in selecting the location and type of intake structure:

- Water level variations in Canals L-63 N&S and C-59
- Flood flow in the canals
- Protection of aquatic life

- Dredging requirement in the canal
- Operation and maintenance

Based on these factors, the selected scheme consists of a pumphouse located on the canal bank and a wedge wire screen with a T-arrangement located in the canal. The wedge wire screen will be at a water depth of about 8 feet at the minimum design water level of 16 feet MSL, as discussed in Section 10.9, the water supply availability study.

A schematic of the layout is shown on Figure 3.5.1-1. The pumphouse includes three 50 percent capacity vertical pumps, air compressor for backwash of the wedge wire screens, and valves and piping for control of the operation.

Two screen assemblies, each with 100 percent capacity, will be installed. The screen will be at least 2 feet above the canal bottom and the top of the screen will be at least 4 feet below the design minimum water level of 16 feet MSL as shown in Figure 3.5.1-2. Each screen has a diameter of 42 inches with an overall length of 12 feet. The design velocity through the slots is less than 0.5 fps. The slot spacings is 1 mm. To prevent local scouring of the canal bottom during the air backwash, riprap will be placed in the vicinity of the screens.

The pump intake structure is located on the canal bank above the 100-year flood level on L-63N. This alternative minimizes the dredging required in L-63N Canal to only that needed to install the two pipes connecting the screens to the intake pumphouse.

This scheme does not lead to fish or larvae entrainment and impingement. Withdrawal of fish eggs by water is precluded due to the small width of the slots. The flow passage in the canal will not be affected by the facilities due to the location of the intake structure and since the screens are supported on piles as shown on Figure 3.5.1-2.

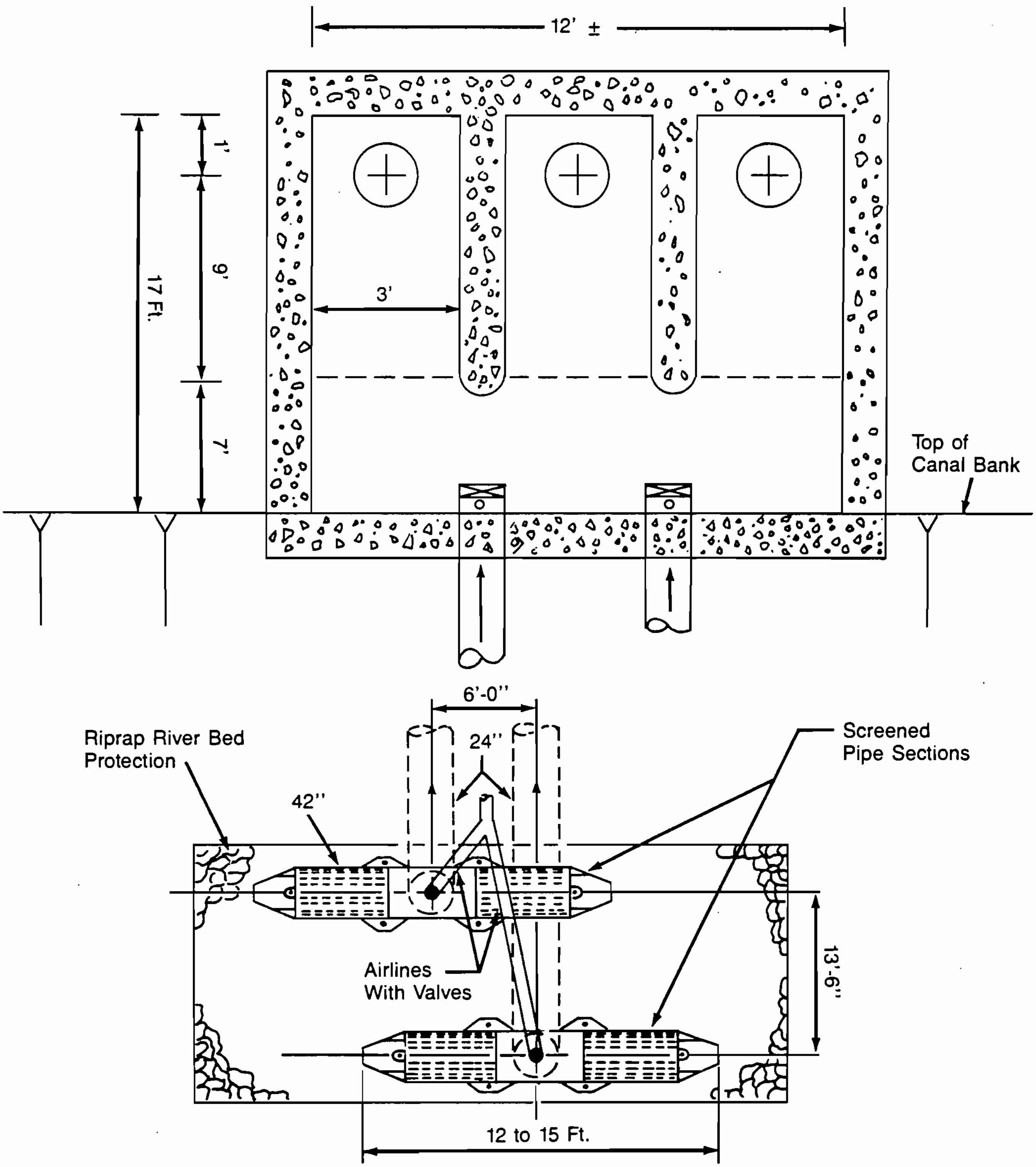

Figure 3.5.1-1.

TAYLOR CREEK/NUBBIN SLOUGH PLANT WATER INTAKE - GENERAL ARRANGEMENT

Source: Bechtel, 1990

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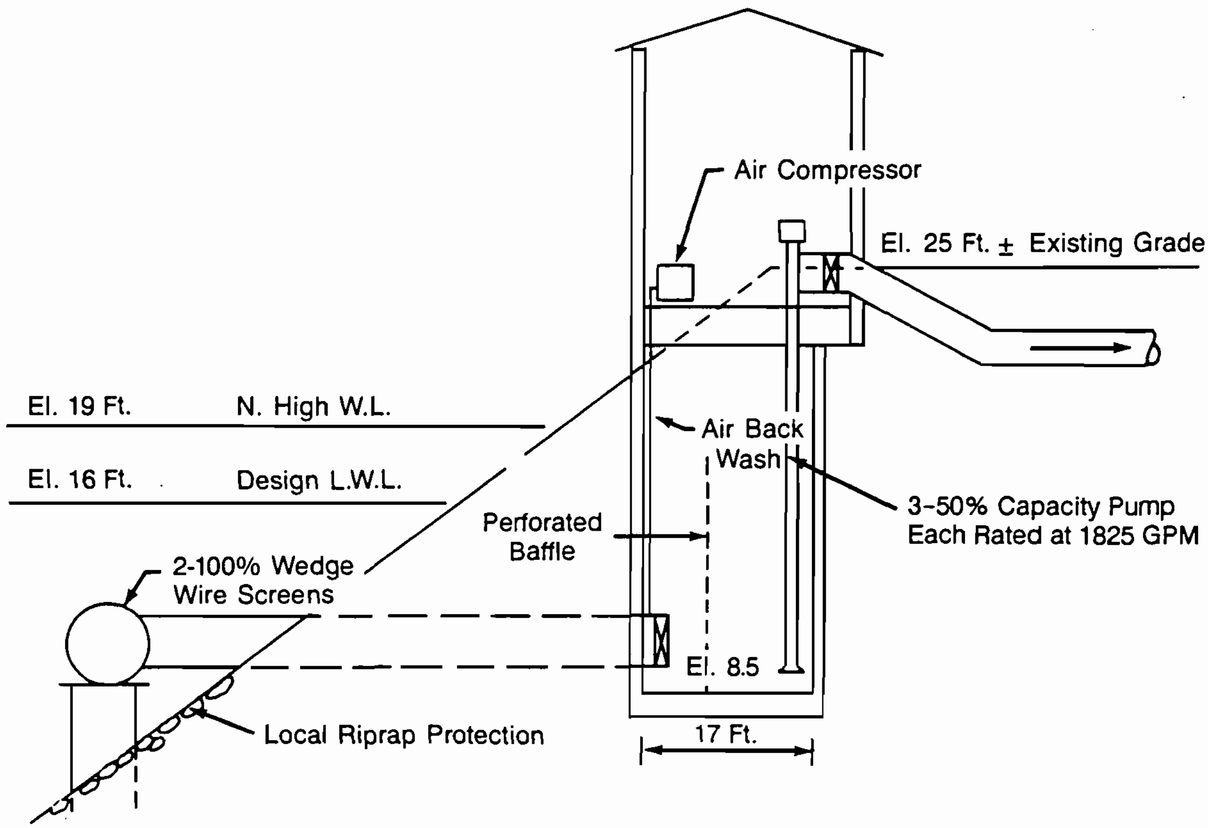

Figure 3.5.1-2.

TAYLOR CREEK/NUBBIN SLOUGH PLANT WATER INTAKE

Source: Bechtel, 1990

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Based on these factors, the selected concept of the intake is considered the best available technology.

Cooling Water Storage Pond

The plant water requirement will be pumped from TC/NS through an 18- to 24-inch diameter pipeline to the onsite storage pond. Riprap protection is provided to the dike slope and pond bottom at the discharge point.

The cooling water storage pond is designed to store water from TC/NS for use in the plant as cooling and process water during short periods of time when TC/NS is unable to supply water to the plant. During extended periods when TC/NS is unable to supply makeup water to the plant, the cooling water storage pond serves as a source to meet a portion of the process makeup water demands of the plant.

The onsite cooling water storage pond is designed to maintain a normal water depth of 6 feet with a bottom area of 22 acres. The pond bottom and the inside embankment side slope is lined with a synthetic liner to prevent seepage. The pond bottom is approximately 2 feet below existing grade; the normal water level is 4 feet above the existing grade. The embankment will be compacted fill with side slopes of 4H:1V.

The pond area and depth are selected to provide approximately 9 to 10 days of cooling water at the average annual makeup requirement and 300,000 gallons of fire water reserve. This volume of fire water requires a water depth of about 1 inch.

As discussed in Section 2.3.3, there is a slight excess of average annual rainfall over evaporation at the ICL site. This excess is not sufficient to significantly lower the makeup water demand from TC/NS; hence, net rainfall into the storage pond is not included in the site water budgets presented in Figures 3.5.0-1 and 3.5.0-2.

The top of the pond embankment is determined considering the normal pond water level, precipitation of 9 inches from a 25-year, 72-hour storm event, and wind setup and wave runup caused by a 100 mph wind. Based on these considerations, a free board of 3 feet is selected. Assuming a normal water level in the pond at an elevation of 38 feet msl, the minimum top of the embankment is at elevation 41 feet msl. In order to pass excess pond storage to avoid over-topping during major storms, an emergency spillway is provided. The spillway crest elevation is approximately 9 inches above normal pond water level.

Cooling Tower

One counterflow, mechanical draft, multi-cell, wooden cooling tower is provided. During operation, 265,000 gpm of cooling water is circulated from the tower basin, through the condenser, and back to the tower. This heated water is distributed to the upper portion of the cells and flows down over a grid that enhances the heat transfer from the water to air. The water flows by gravity, countercurrent to the ambient air. Most of the heat is removed by evaporating a portion of the cooling water; the remainder is removed by sensible heat transfer to the air. Cooled water is collected at the bottom of the tower in a concrete basin.

Cooling water makeup is withdrawn from the cooling water storage pond and transferred to the basin when using the TC/NS source of water. When using the backup source of water, makeup water from the lower production zone of the upper Floridan aquifer is transferred directly to the cooling tower basin from the wells.

The air flowing up through the cooling tower entrains a small amount of the cascading water and carries this water out of the tower as drift. Mist eliminators and operator control of the air to water ratio in the tower minimize drift losses from the cells to 0.002 percent of the circulating water flowrate, or slightly more than 5.3 gpm.

The evaporation of water in the cooling tower concentrates dissolved solids in the circulating water. As a result, a portion of the circulating water is continuously discharged as a blowdown from the cooling system to maintain a solids balance. The ratio of the cooling tower makeup requirement to the sum of cooling tower blowdown and drift losses is called the cycles of concentration (COC). This ratio relates the blowdown and drift water quality to the makeup water quality.

Sidestream Softener

The cooling water system includes a sidestream softener. A portion of the circulating water is passed through a sidestream softener where the levels of dissolved iron and hardness ions in the water are lowered. The softener system consists of a flash mixing tank, a flocculation chamber, and a clarifier. The circulating water flows into a flash mixing tank where lime, soda-ash, and polymer are added to the water. The water then flows to a flocculation chamber where contact is induced between precipitates and suspended matter. Finally, the water flows to a large clarification zone that uses gravity to settle out the suspended solids. A long detention time is provided for settling of suspended solids. A rake circles the bottom of the clarifier to collect settled sludge and remove it through a sump.

Cooling Water Treatment

The cooling water system is designed to use two sources of cooling water. TC/NS is the primary source of cooling water makeup and the lower production zone of the upper Floridan aquifer serves as a backup when the TC/NS source is not available. A small wastewater stream from the boiler blowdown is also recycled to the cooling tower due to its relatively good quality. As shown in Table 3.5.0-2, the TC/NS source contains high levels of iron, calcium, and alkalinity while the lower production zone of the upper Floridan aquifer has a high total dissolved solids level and natural bicarbonate alkalinity. Due to the differences in quality of the two sources, the cooling tower will operate at different cycles of concentration (COC) when using each source. The cooling tower is designed to allow the maximum possible cycles of concentration without causing scaling and corrosion. At higher COC, both the makeup and blowdown flowrates decrease. The high levels of iron, calcium, and alkalinity in TC/NS would cause scaling and corrosion problems above two COC without substantial use of inhibitors. Similarly, high levels of hardness ions, alkalinity, and total dissolved solids in the lower production zone of the upper Floridan aquifer limit the COC when this source is utilized. Therefore, a sidestream softener is provided to treat a portion of the circulating water to remove iron and hardness ions from the circulating water. This lowers their concentration in the circulating water and allows for higher COC. However, increasing the COC also increases the size of the sidestream softener. At 10 COC for the TC/NS cooling water source and 3.5 COC for the lower production zone of the upper Floridan aquifer, balances are reached between the makeup water demand, the size and chemical use of the sidestream softener, and the concentration of dissolved solids in the blowdown.

Thermal Performance of the Tower

Tables 3.5.1-1 and 3.5.1-2 present performance data for operation of the cooling tower at 10 COC and 3.5 COC, respectively, at a 100 percent load factor, circulating water flowrate of 265,000 gpm, drift losses of 0.002 percent of the circulating water flowrate, temperature rise of 12.6 °F across the condenser, and the average monthly temperatures listed in the tables.

The design conditions for the cooling tower, from which the maximum daily makeup water demands presented in Section 3.5 are determined, are a dry bulb temperature of 91 °F (which corresponds to a wet bulb temperature of 80 °F) and hot water and cold water temperatures of 102.6 °F and 90 °F, respectively.

Table 3.5.1-1
COOLING TOWER PERFORMANCE DATA AT 10 CYCLES OF CONCENTRATION

Month	Dry Bulb Temp (°F)	Evaporation (GPM)	Blowdown (GPM)	Makeup (GPM)
January	65.6	2418	268	2686
February	66.7	2435	270	2705
March	70.1	2478	275	2753
April	73.8	2570	285	2856
May	77.7	2597	288	2886
June	80.8	2612	290	2902
July	82.4	2620	291	2911
August	82.7	2626	291	2917
September	81.5	2600	288	2889
October	77.7	2597	288	2886
November	72.1	2481	275	2756
December	67.8	2441	271	2712
Annual Average	74.9	2540	282	2822

Notes:

1. Dry bulb temperatures are average monthly temperatures recorded by the National Weather Service at West Palm Beach, Florida between 1958 and 1987.
2. Cooling tower flows are based on 100 percent load factor, circulating water flowrate of 265,000 gpm, drift losses of 0.002 percent of circulating water flowrate, and a temperature rise across the condenser of 12.6 °F.

Source: Bechtel, 1990

Table 3.5.1-2
COOLING TOWER PERFORMANCE DATA AT 3.5 CYCLES OF CONCENTRATION

Month	Dry Bulb Temp(°F)	Evaporation (GPM)	Blowdown (GPM)	Makeup (GPM)
January	65.6	2418	967	3385
February	66.7	2435	974	3409
March	70.1	2478	991	3469
April	73.8	2570	1028	3598
May	77.7	2597	1039	3637
June	80.8	2612	1044	3657
July	82.4	2620	1048	3668
August	82.7	2626	1050	3676
September	81.5	2600	1040	3641
October	77.7	2597	1039	3637
November	72.1	2481	992	3473
December	67.8	2441	976	3417
Annual Average	74.9	2540	1015	3556

Notes:

1. Dry Bulb Temperatures are average monthly temperatures recorded by the National Weather Service at West Palm Beach, Florida between 1958 and 1987.
2. Cooling tower flows are based on 100 percent load factor, circulating water flowrate of 265,000 gpm, drift losses of 0.002 percent of circulating water flowrate, and a temperature rise across the condenser of 12.6 °F.

Source: Bechtel, 1990

3.5.1.2 Sources of Cooling Water

The primary source of cooling water for the ICL plant is surface water from TC/NS. During periods of extended drought when water from TC/NS is not available, cooling water will be withdrawn from the lower production zone of the upper Floridan aquifer. Section 10.9 presents the analysis of water availability from TC/NS. Based on the historic data records, the maximum estimated duration of withdrawal from the lower production zone of the upper Floridan aquifer is about 3 months. The volume of water required during that time is presented in Table 3.5.0-1. Qualities for the TC/NS and the lower production zone of the Floridan aquifer are provided in Table 3.5.0-1.

The design of the cooling water treatment equipment allows for significant variation in the water quality from TC/NS without severely impacting the operation of the cooling tower. As discussed in Section 3.5.1.1, the cooling water treatment system uses the sidestream softener to control the level of dissolved iron and hardness ions in the circulating water. The sizing of the sidestream softener is governed by use of the lower production zone of the Floridan aquifer as the cooling water source. When TC/NS is the source of cooling water, less sidestream softening is required to maintain the desired COC. Therefore, if the iron, calcium, magnesium, or alkalinity levels in the TC/NS source are higher, more circulating water can be treated in the sidestream softener to control the concentration of these ions.

The quality of aquifer waters does not generally fluctuate as does the quality of surface waters. The sizing of the sidestream softener when using the lower production zone of the upper Floridan aquifer is based on the cooling tower operating at the design meteorological conditions and the water quality. In addition, the design of the sidestream softener and chemical feed system are based on a conservative throughput rate, allowing treatment of higher flowrates, if necessary to maintain the COC.

3.5.1.3 Dilution System

No dilution of cooling water is needed because the ICL plant water and wastewater treatment scheme does not include a discharge to a surface water.

3.5.1.4 Blowdown, Screened Organisms, and Trash Disposal

Blowdown from the cooling tower is transferred to the wastewater treatment system where it is recycled as much as practicable with the remainder disposed of by injection to the Boulder Zone of the lower Floridan aquifer. Section 3.6 describes the incorporation of cooling tower blowdown into the wastewater treatment scheme.

The makeup water intake at TC/NS does not have trash collection since submerged wedge wire screens will be used. Compressed air is used to backwash the wedge wire screens when required. Organic debris and trash in the cooling water storage pond are collected by fixed screens at the intake structure on the pond. Any trash such as floating leaves or debris will be collected and disposed of according to Section 3.7.

3.5.1.5 Injection Wells

Injection wells are proposed for the disposal of cooling system and process wastewaters produced at the ICL plant. This section addresses the feasibility of injection of such industrial wastewater at the ICL site based on the known and expected hydrogeology. Conceptual designs for the injection and monitor wells are presented. The construction and testing program is outlined and the injected fluid is characterized. An injection system monitoring plan is presented.

The injection wells will be designed to comply with the requirements for underground injection control (FAC 17-28). As part of this regulation, a Technical Advisory Committee (TAC) is established for each application to ensure the system is designed properly and will operate according to the design. The ICL TAC will consist of agency personnel from the DER's regional and main offices, the SFWMD, EPA Region IV, and the Fish and Wildlife.

Background

The wastewater from the ICL facility is proposed to be injected into Class I injection wells. Class I wells inject wastewater beneath the lowermost formation containing an underground source of drinking water (USDW), defined as 10,000 mg/l TDS or less.

The wastewater from various sources will be collected in a wastewater collection tank. A portion of this wastewater will be recycled and used in the spray dryer dilution system. The remainder will be disposed of in the injection well. As discussed in Section 3.6, the wastewater from this facility is expected to be non-hazardous.

Maximum daily flow (MDF) to the injection wells at the ICL facility is anticipated to be 1,280 gallons per minute (gpm). The proposed location of the injection wells onsite is shown on Figure 3.1.1-1.

Feasibility of Injection Well Disposal

The feasibility of injection well disposal at the ICL site can be assessed from the performance of injection wells in St. Lucie, Martin, and Palm Beach Counties. Data were reviewed on the existing injection wells in those counties to evaluate the regional hydrogeology and to extrapolate the findings to the Indiantown area.

Within a 25-mile radius of the site, several injection wells have been operational for up to 13 years (North Port St. Lucie, 1988; South Port St. Lucie, 1983; City of Stuart, 1982; Pratt and Whitney, 1985; QO Chemicals, Inc., 1977; Seacoast Utilities, 1989). All of these wells inject into the lower Oldsmar Formation (Boulder Zone) at depths of 2,900 to 3,300 feet below land surface (bls).

In south Florida, sedimentary rock types such as dolomite and fractured limestone are potentially good injection zones. Injection zones must be adequate in thickness and areal extent to receive the proposed volume of injected fluid. Overlying formations should be essentially horizontal and without faults or fractures. The proposed injection zone also should have sufficient porosity and permeability to accommodate the proposed flow without undue pressure buildup.

Typical confining strata in Florida include clays and unfractured limestones. Because of the potential for fractures or solution channels in the limestones and dolomites, site-specific demonstration of the adequacy of the proposed confining strata is required by state underground injection control regulations. Factors considered in demonstrating this adequacy include lithology, thickness, areal extent, structure, porosity, and permeability. The overlying rock unit proposed to provide confinement must be sufficiently thick and areally extensive, free of fractures or faults, and of sufficiently low porosity and permeability to retard the upward migration of injected fluids.

Regional Geology

Data were obtained on the existing injection and test wells in Martin and neighboring counties to evaluate the regional geology and extrapolate the findings to the Indiantown area. Table 3.5.1-3 is a summary of the well locations used. Figure 3.5.1-3 is a location map of the referenced wells, and Figure 3.5.1-4 is a cross section from A-A'. A lithologic log of the Amerada Cowles Magazines Inc. No. 1 well was obtained from the Florida Geological Survey files (Reference No. W-4086). This well is approximately 12 miles north-northeast from the site, and was drilled to over 5,000 feet in depth. Based on the data obtained from these

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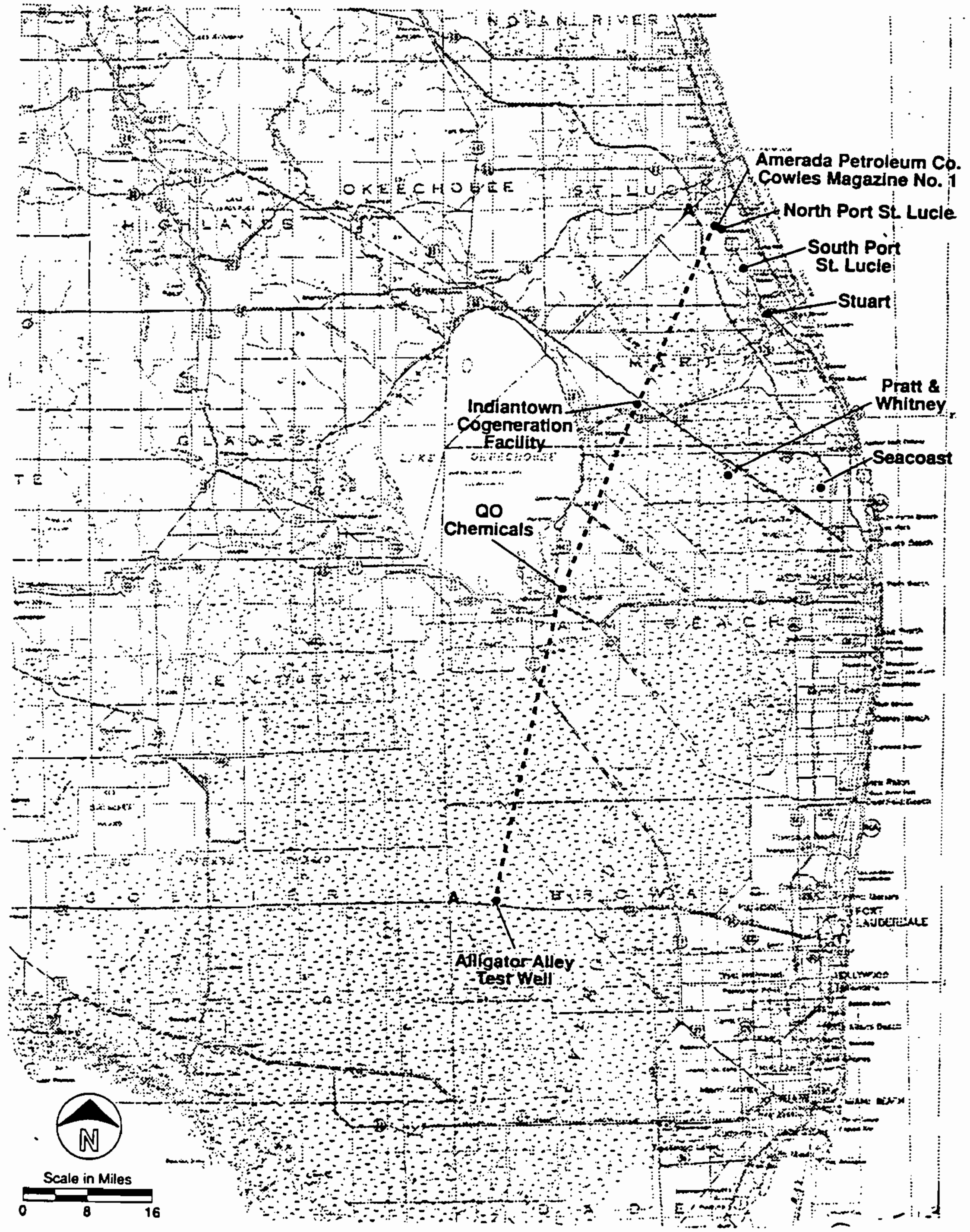

Figure 3.5.1–3
LOCATION OF GENERALIZED NORTH–SOUTH GEOLOGIC CROSS SECTION AND ADJACENT INJECTION WELLS

Source: CH2M Hill, 1990

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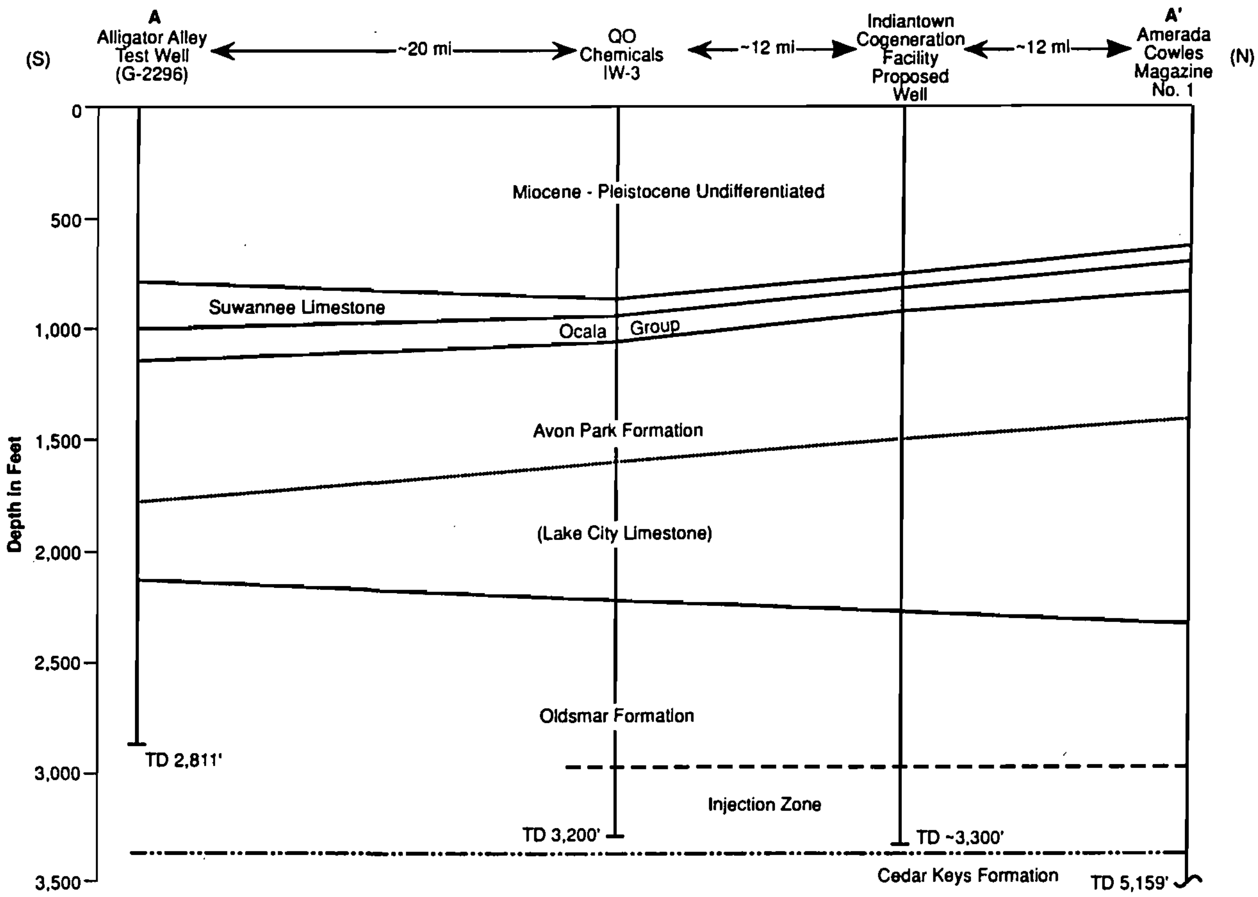

Source: Chen, 1965; Puri and Winston, 1974; Meyer, 1988.

Figure 3.5.1–4
GENERALIZED NORTH–SOUTH GEOLOGIC CROSS SECTION

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Table 3.5.1-3
INJECTION AND TEST WELL LOCATIONS

Well	County	Section/ Township/Range	Depth (feet)
Amerada Cowles Magazine No. 1	St. Lucie	Sec. 19 T36S, R40E	5,159
Indiantown Cogeneration Facility (proposed)	Martin	Sec. 35 T39S, R37E	3,300 (est.)
North Port St. Lucie	St. Lucie	Sec. 20 T36S, R40E	3.324
South Port St. Lucie	St. Lucie	Sec. 13 T37S, R40E	3,418
Pratt & Whitney	Palm Beach	Sec. 14 T41S, R40E	3,320
Florida Power and Light	Martin	Sec. 25 T39S, R37E	1,056*
QO Chemicals	Palm Beach	Sec. 28 T43S, R37E	3,156
Alligator Alley Test Well	Broward	Sec. (N/A) T50S, R35E	2,811
Stuart	Martin	Sec. 1	3,305
Seacoast	Palm Beach	Sec. 4 T42S, R42E	3,320

*Test Well

wells, the Cedar Keys Formation is the oldest formation expected to be encountered during drilling of the injection wells, at an approximate depth of 3,200 feet.

Regional Hydrogeology

Injection Zone

The stratum most commonly used for injection in southeast Florida is the lower portion (Boulder Zone) of the Oldsmar Formation. Water quality in this zone typically exceeds 30,000 mg/l TDS. The principal overlying confining units are the upper Oldsmar Formation and the lower part of the Avon Park Limestone.

The dolomitic portions of the lower Oldsmar Formation are finely crystalline and sucrosic, with areas that are highly fractured and cavernous. Cavities in the lower Oldsmar Formation range in size from small vugs to large caverns. The caverns persist to the base of the formation, where interbedded dolomite and anhydrite of the Paleocene age Cedar Keys Formation are encountered. The existence of these formation characteristics in south Florida accounts for the success of injection wells there.

The areal extent of the lower Oldsmar Formation is well documented in the literature and well data. Chen (1965) postulates that during the early Tertiary age, Florida existed as a broad carbonate platform, with warm and shallow marine conditions similar to the present-day Bahamas and Compeche Bank. Carbonates were deposited throughout the Florida platform. The Oldsmar Formation is present in all of peninsular Florida and exhibits the greatest degree of dolomitization along the structural high of the Peninsular arch. The thickness of the Oldsmar Formation varies from approximately 400 feet along the crest of the Peninsular arch to as much as 1,200 feet in south Florida.

Puri and Winston (1974) identified areas suitable for injection in south Florida in their regional study. The Amerada Cowles Magazine Inc. No. 2 well adjacent to

No. 1 (referenced by Chen, 1965) in St. Lucie County has zones of high transmissivity in the middle to lower Oldsmar Formation that are approximately 2,300 to 3,200 feet in depth. The North Port St. Lucie well has injected successfully in the interval between 2,900 and 3,200 feet since 1988, while the QO Chemicals wells have successfully used that same interval since 1977.

Depth to Base of USDWs

The relationship of the location of the interface between fresh water and water containing greater than 10,000 mg/l of TDS to the injection and confining zones is one factor determining the feasibility of injection at a particular site. Ideally, the base of fresh water should occur near the top of the confining sequence.

Regionally, the 10,000 mg/l TDS interface occurs in the interval between 1,600 and 1,850 feet in depth. At the City of Stuart's injection well, the depth to the interface occurs in the 1,600- to 1,700-foot interval, while at the North Port St. Lucie well the interface occurs at approximately 1,700 feet in depth. At both the Pratt & Whitney and the QO Chemicals wells, the interface occurs at approximately 1,800 feet in depth.

Confining Zone

Eocene carbonates are the principal stratigraphic units providing confinement and have been found in every injection well drilled in southeast Florida. The structure contour maps and isopach-lithofacies maps Chen (1965) developed attest to the regional areal extent of the formations that provide confinement to the injection zone. An approximately 1,100-foot-thick confining sequence found at the North Port St. Lucie site increases to a thickness exceeding 1,300 feet at the City of Stuart.

Results of core analyses from the North Port St. Lucie well are shown in Table 3.5.1-4. The average permeability was found to be about 1.0 X 10^{-5} cm per second. This is consistent with permeability values found in other wells in the area.

Table 3.5.1-4
CORE ANALYSIS SUMMARY
NORTH PORT ST. LUCIE INJECTION WELL

Depth (feet)	Orientation (Horizontal or Vertical)	Coefficient of Permeability (cm/sec)	Porosity (%)
2101.0-2101.8	V	4.5×10^{-5}	35
2101.0-2101.8	H	5.4×10^{-5}	35
2108.2-2109.0	V	4.4×10^{-5}	32
2108.2-2109.0	H	3.3×10^{-5}	31
2249.0-2250.0	V	3.5×10^{-7}	13
2249.0-2250.0	H	1.4×10^{-7}	9
2253.5-2254.0	V	2.8×10^{-3}	37
2253.5-2254.0	H	1.2×10^{-3}	32
2425.0-2426.2	V	6.7×10^{-4}	35
2425.0-2426.2	H	5.7×10^{-4}	35
2430.0-2431.0	V	1.6×10^{-5}	34
2430.0-2431.0	H	3.4×10^{-4}	36
2449.0-2450.0	V	3.5×10^{-6}	35
2449.0-2450.0	H	8.9×10^{-5}	38
2451.0-2451.8	V	2.3×10^{-5}	31
2451.0-2451.8	H	1.1×10^{-5}	30
2628.0-2629.0	V	4.1×10^{-5}	25
2628.0-2629.0	H	1.9×10^{-4}	30
2632.5-2633.0	V	5.0×10^{-4}	31
2632.5-2633.0	H	1.5×10^{-4}	32

Note: Core analyses performed by Ardaman and Associates, Orlando, Florida.

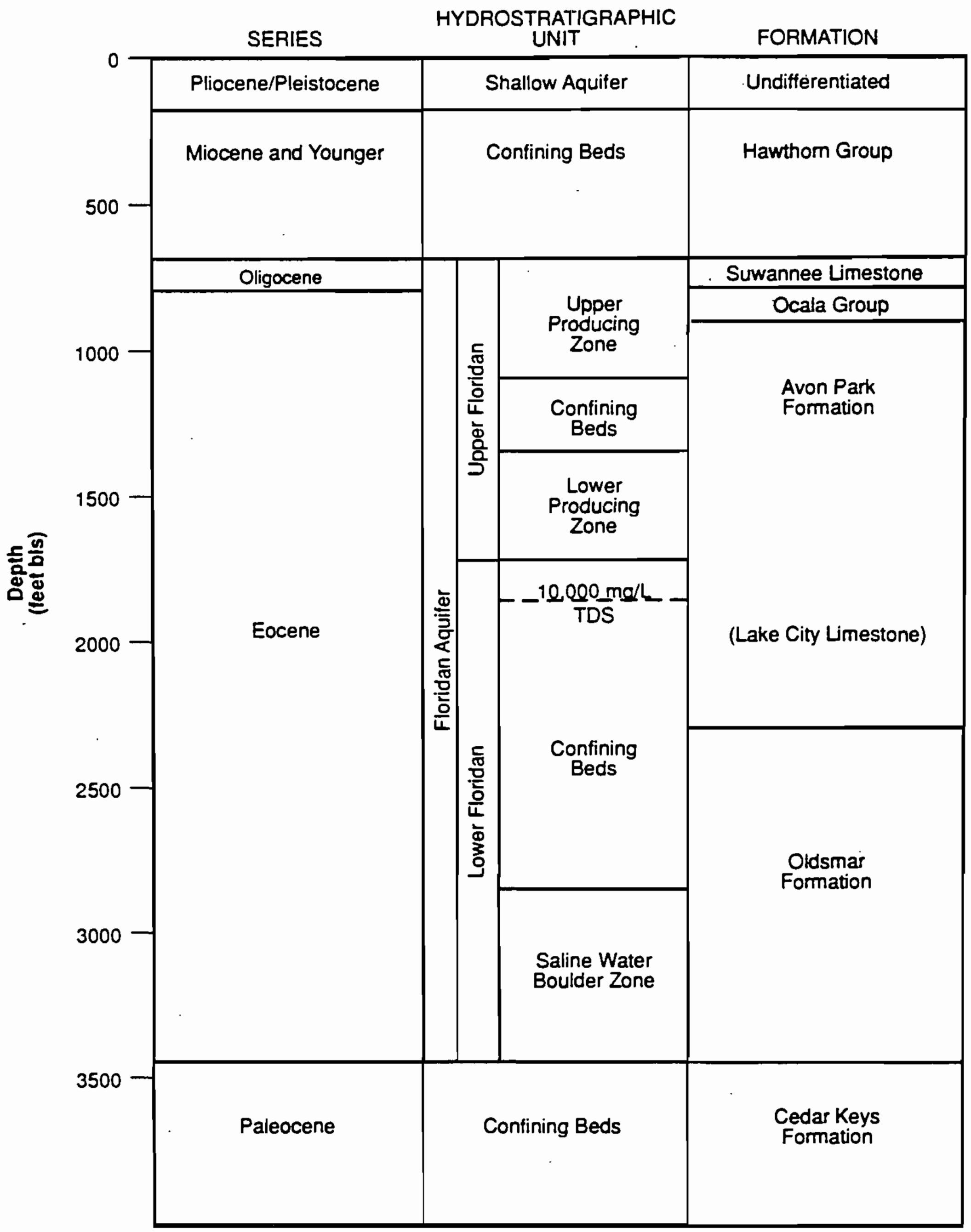
These data indicate that the confining beds above the injection zone are of sufficient thickness and areal extent to retard the upward migration of fluids and should be present at the ICL site.

Expected Hydrogeology at the Site

The hydrogeology in the vicinity of Indiantown is reasonably well documented from injection wells that have been drilled within a 25-mile radius, test oil wells that have been drilled in the vicinity, and from published regional studies. The data strongly suggest that the formations used in south Florida for injection and confinement will be encountered at the proposed ICL facility. Rock formations that are important to the injection process are found throughout the region. They dip gently seaward (Miller, 1986) and lack structural features that could affect their suitability for injection. It is expected that the hydrogeology and formation boundaries beneath the proposed site are similar to those beneath the Amerada Cowles and QO Chemicals sites.

In the cross section shown on Figure 3.5.1-4, the injection zone occurs at about the same depths from north to south, at approximately 2,900 feet. The injection zone at the Pratt & Whitney well also occurs at that depth.

Figure 3.5.1-5 shows the anticipated hydrogeology at the ICL site. The top of the injection zone is expected to occur at a depth of approximately 2,900 feet and extend to a depth of 3,200 feet. The confining sequence is expected to extend from a depth of about 1,850 feet to the top of the injection zone. It is anticipated, based on the location of the 10,000 mg/l TDS interface at the Pratt & Whitney, QO Chemicals, Stuart, and Port St. Lucie wells, that the 10,000 mg/l TDS interface at the ICL site will occur between 1,750 and 1,850 feet bls.



Source: Chen, 1965; Lichtler, 1960; CH2M HILL files.

Figure 3.5.1–5
GENERALIZED HYDROGEOLOGIC COLUMN AT THE INDIANTOWN COGENERATION FACILITY

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Conceptual Design

Injection System Plan

The injection and monitor wells will be located on a reinforced concrete pad, typically 8 to 12 inches thick and approximately 80 x 180 feet in size. The pad will protect the Surficial aquifer from spills and supports drilling loads during construction and workovers. The proposed location for the injection and monitor wells is shown on Figure 3.5.1-6.

The injection system will include a main injection well, standby injection well, a two-zone monitoring well, pumps, surge tank, and instrumentation and controls. The wastewater will be collected in a tank and level switches in the tank will control the injection pumps. The wastewater will normally be pumped to the main injection well. If the main injection well is out of service, the standby injection well will be used. The injection piping will be connected to the hydraulic surge control system.

The hydraulic surge control system will be designed to dissipate hydraulic surges caused by an increase or decrease in the flow velocity within the piping system. The surge control system will consist of a surge tank, air source, and a level control system. The system components will be sized based on actual flows and pressures. Figure 3.5.1-7 is a conceptual diagram of the injection system.

Water Supply

The primary water supply for cooling tower makeup will be Taylor Creek/Nubbin Slough, located approximately 19 miles northwest of the site. Occasionally, makeup water will be required to be withdrawn from the Floridan aquifer. Taylor Creek/Nubbin Slough will be used as long as specific hydraulic conditions are met in the canal system. During periods of extended drought, water will be required to be withdrawn from Floridan aquifer wells constructed at the facility.

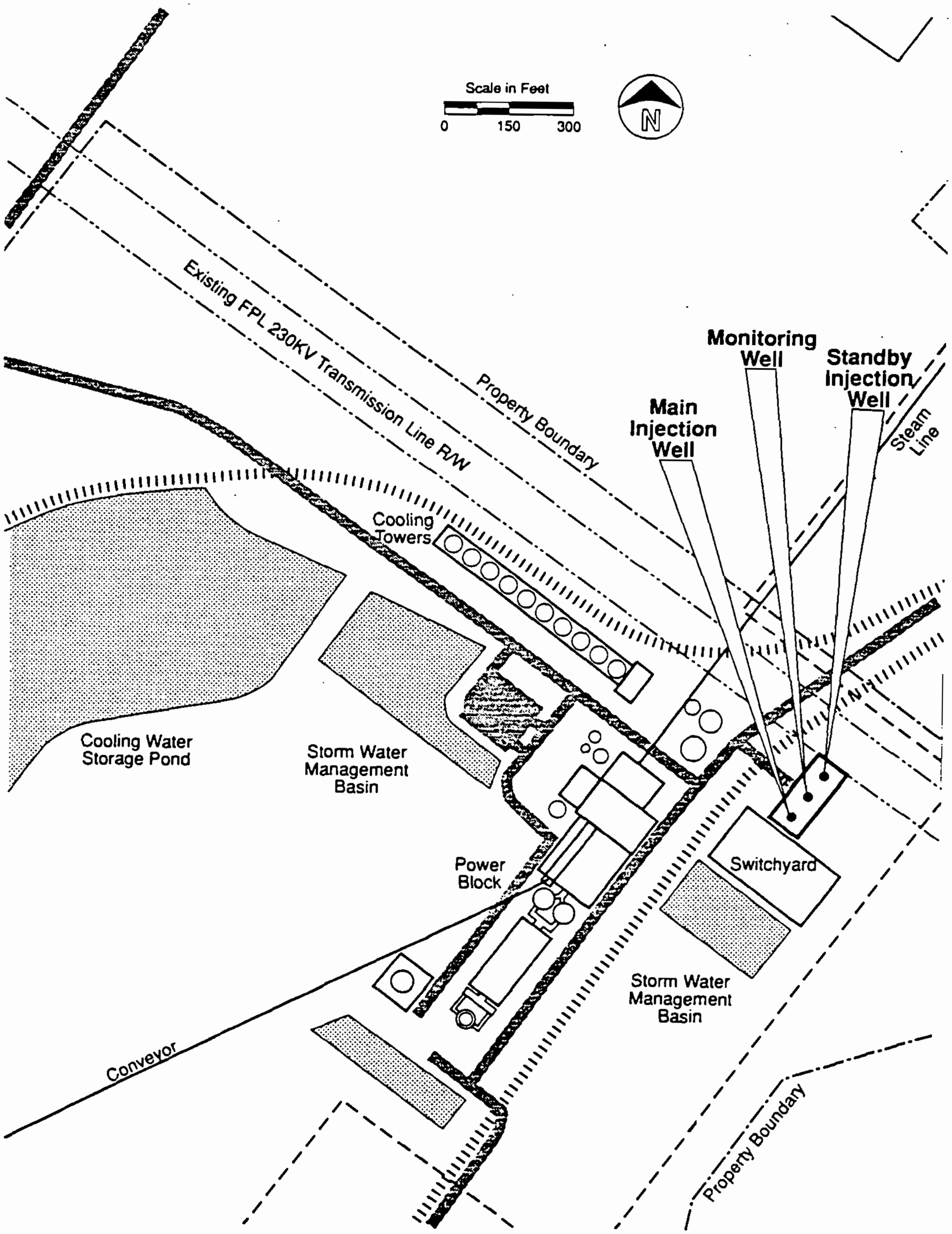

Figure 3.5.1–6
DETAILED SITE PLAN OF THE INDIANTOWN COGENERATION FACILITY

Source: CH2M Hill, 1990

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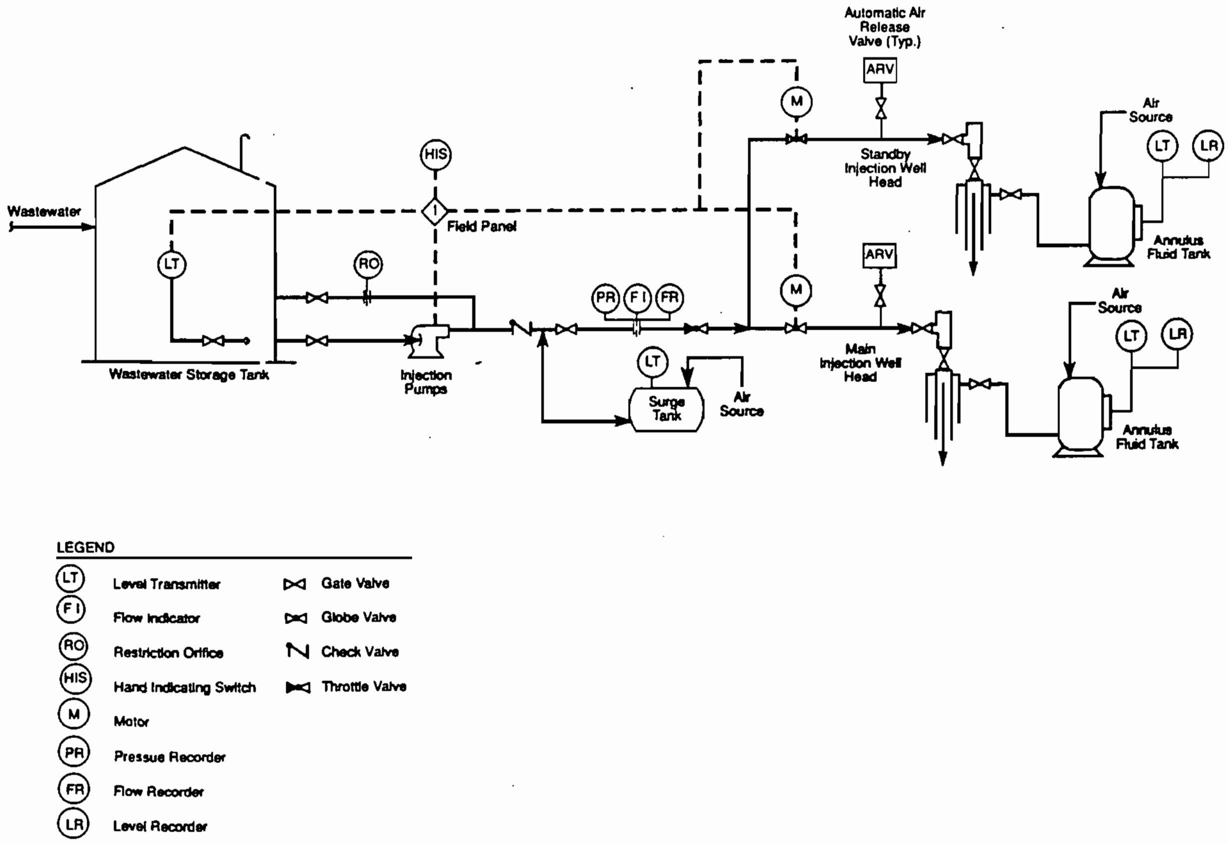

Figure 3.5.1–7
CONCEPTUAL INJECTION SYSTEM DIAGRAM,
INDIANTOWN COGENERATION FACILITY

Source: CH2M Hill, 1990

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The raw water quality of the two sources will result in different concentration cycles in the cooling tower. The resulting wastewater quality and quantity will be different depending on the raw water source. The estimated peak flow to the injection well when utilizing the canal source is 250 gallons per minute (gpm). The estimated peak flow to the well when utilizing the Floridan aquifer is 1,280 gpm.

Injection Tubing Size

The Florida Department of Environmental Regulation (FDER) has developed a limitation on the flow velocity of injected fluids in the injection casing or tubing. The maximum flow velocity allowed is 8 feet per second (fps). This criterion is typically the limiting factor in determining the capacity of an injection well.

The injected flow will reach rates up to 1,280 gpm when the Floridan aquifer is utilized for water supply. A 10-inch diameter injection tubing will be required to accommodate this flow. At 8 fps fluid velocity, the allowable flow in the 10-inch tubing will be about 1,714 gpm. Each injection well will be designed to accept the maximum wastewater flow, thereby providing 100 percent redundancy for the injection well system.

Material Selection Criteria

The intermediate casings of the injection wells will be carbon steel as is typically used on Class I injection wells. The injection tubing material will be selected to provide a reliable mechanical system for injection. The injected fluid will be slightly brackish when utilizing Taylor Creek/Nubbin Slough, and will be moderately brackish when the Floridan aquifer is used for supply. The tubing material will be selected to be compatible with the brackish nature of the wastewater. Possible tubing materials include carbon steel, internally coated carbon steel, fiberglass reinforced plastic, and other specialty metals.

Final material selection will be based on suitable mechanical properties, capital costs, operation and maintenance costs, and corrosion resistance.

Preliminary Design

The conceptual design of the injection wells is based on providing capacity for maximum daily flow without any storage and on the regulatory limitation on flow velocity of 8 fps. The preliminary design of the injection wells is presented on Figure 3.5.1-8. This design is based on the assumption that fiberglass reinforced plastic (FRP) tubing will be used for the injection tubing. The FRP couplings in this size have an outside diameter of 12.625 inches. If coated steel or alloy steel is used, the casing sizes may be reduced because the coupling dimensions are smaller than for a similar size FRP tubing.

A 10-inch-diameter tubing set with a packer will be required to accommodate the maximum 1,280 gpm flow. A 16-inch-diameter final casing, set to the top of the injection zone, will be required to provide adequate clearance for the packer and tubing couplings. The remaining casing sizes are proposed to be 26, 34, and 42 inches in diameter. Intermediate casings are included in injection well designs to facilitate construction and to protect overlying aquifers.

Construction and Testing Plan

Drilling Program for Injection Wells

The injection wells will be constructed by advancing the hole with a pilot hole, reaming the pilot hole, installing casing, and progressing with the pilot hole to install the next smaller-sized casing. Testing will occur throughout the drilling process. The proposed drilling and testing program for each injection well is described below.

1. Install by driving or drilling a minimum 42-inch-diameter surface casing to about 25 to 40 feet in depth; cement the annulus back to surface if drilled. Drill a 12-inch-diameter pilot hole through the Surficial aquifer and underlying clay into the consolidated limestone at an approximate depth of 500 feet. Run geophysical logs.

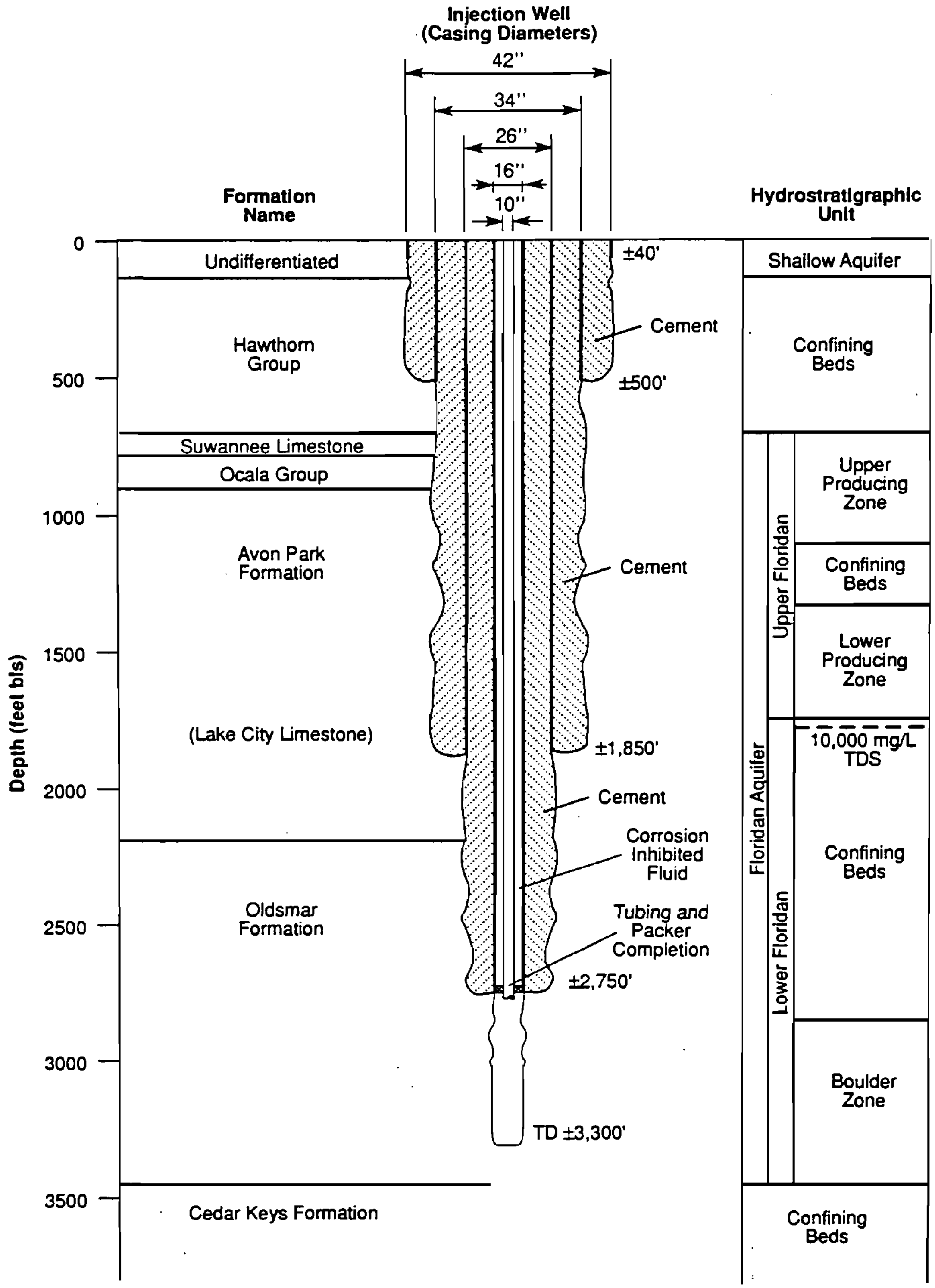

Figure 3.5.1-8.

PRELIMINARY DESIGN OF THE INDIANTOWN COGENERATION FACILITY INJECTION WELL

Source: CH2M Hill, 1990

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2. Ream the 500-foot pilot hole to about 42 inches in diameter; install approximately 500 feet of 34-inch-diameter casing and cement the annulus to ground surface. Advance the 12-inch-diameter pilot hole to approximately 1,850 feet. Run packer tests to identify the base of the USDW. Run a suite of geophysical logs.

3. Ream the pilot hole to total depth; install a 26-inch-diameter casing to about 1,850 feet and cement the annulus to surface. Drill the pilot hole to a depth of 3,300 feet. During pilot hole drilling for one of the injection wells, obtain five 10-foot rock cores from the 2,000- to 2,700-foot depth interval, run four packer tests in the same interval, and perform a suite of geophysical logs. Packer tests will be run to evaluate the confining beds and to select the lower monitoring zone.

4. Set a bridge plug in the final pilot hole to permit installation of the final 16-inch-diameter casing. The bridge plug will be set immediately below the intended casing installation depth of 2,750 feet. Ream the pilot hole to a depth of about 2,760 feet and install the 16-inch-diameter casing to an approximate depth of 2,750 feet. Cement the annulus to the surface in stages.

5. Run temperature and gamma logs inside the 16-inch-diameter casing after the first stage of cement to pick the top of that stage. Run a 1-hour pressure test and a cement bond log on the final casing.

6. Drill out the bridge plug and clean out the hole to a total depth of approximately 3,300 feet. Run geophysical logs to total depth.

7. Install the 10-inch-diameter tubing with a packer assembly set just above the bottom of the final casing.

8. Run a suite of geophysical logs, TV survey, and a radioactive tracer survey.

Drilling Program for Monitor Well

The current regulatory requirements for monitoring the aquifers above the injection zone are to monitor the first permeable zone above the injection zone and the base of the USDW. The first permeable zone above the injection zone typically occurs at a depth of about 2,000 to 2,100 feet and the water in this interval is salty. Because it is not a USDW, monitoring in this zone provides an early warning of injected fluid migration in the direction of the USDW. The 10,000 mg/l TDS isochlor is expected to occur between approximately 1,750 and 1,850 feet in depth at the ICL facility.

The monitor well is designed to monitor the two zones required by regulations. An open annulus between the 6- and 14-inch- diameter casings will be provided near the base of the USDW to monitor the interval from about 1,600 to 1,650 feet. The 6-inch diameter casing will be set to a depth of approximately 2,000 feet and the hole extended to monitor the interval from about 2,000 to 2,100 feet. Figure 3.5.1-9 shows the proposed monitor well design.

Drilling of the pilot hole, geophysical logging, and reaming and casing installation will be performed as follows.

1. Install an approximately 30-inch-diameter surface casing by driving or drilling to about 40 feet in depth; cement the annulus back to surface if drilled. Drill a 12-inch-diameter pilot hole through the Surficial aquifer and underlying clay into competent rock at an approximate depth of 500 feet. Run geophysical logs.

2. Ream the pilot hole to 500 feet in depth; install about 500 feet of 20-inch-diameter casing and cement the annulus back to surface.

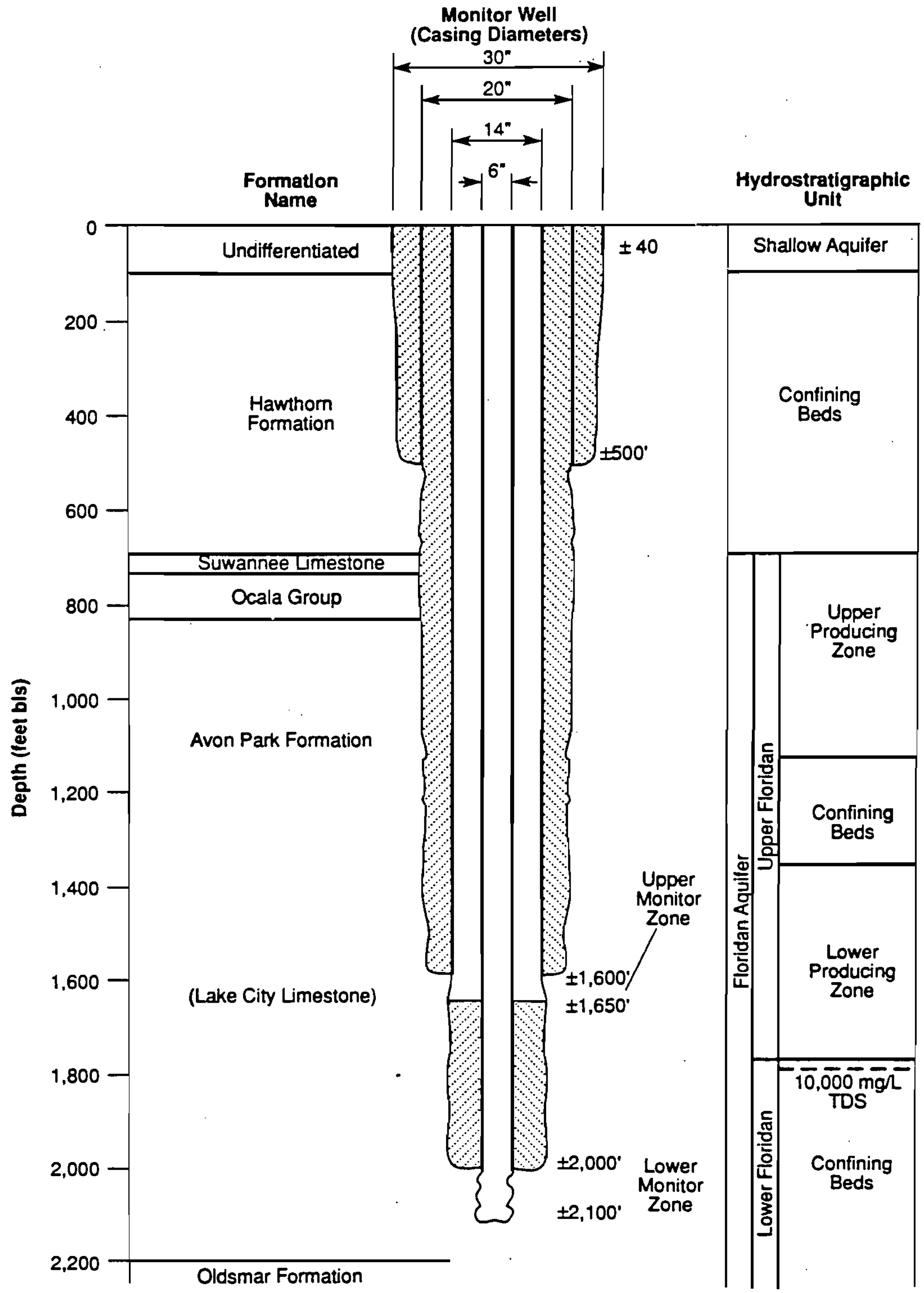

Figure 3.5.1-9.

PRELIMINARY DESIGN OF THE INDIANTOWN COGENERATION FACILITY MONITOR WELL

Source: CH2M Hill, 1990

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Continue pilot hole drilling to about 1,200 feet in depth. Run geophysical logs. Install a test pump and pump the well for the injection tests on the injection wells.

3. Resume drilling the 12-inch-diameter pilot hole to a depth of 1,600 feet. Run geophysical logs.

4. Ream the 1,600-foot pilot hole to about 20 inches in diameter; install approximately 1,600 feet of 14-inch-diameter casing and cement the annulus back to surface. Run geophysical logs. Advance the 12-inch-diameter pilot hole to approximately 2,000 feet and run a suite of geophysical logs.

5. Install a 6-inch-diameter casing to about 2,000 feet and cement the annulus up to about the 1,650-foot depth. Run a pressure test on the 6-inch diameter casing for 1 hour. Run geophysical logs.

6. Drill out the hole to a depth of 2,100 feet and run geophysical logs. Develop the lower zone by airlifting and allow the upper zone to flow until background conditions return and background water quality samples are taken.

Casing Grout Program

After each casing is set, it will be cemented in place by a multi-staged process using ASTM Type II neat cement mixed with 2 to 12 percent bentonite. A specific cementing program will be developed for each casing and modified as necessary in the field based on data obtained during drilling. The cement formulations are typically based on the fluid loss properties of the formations being cemented. Lighter formulations are used when highly permeable formations are encountered.

After each casing is positioned at the setting depth, a grout pipe is lowered inside the casing to within approximately 25 feet of the casing bottom and a header is installed on the casing to seal the grout pipe and casing. The first stage of cement is pumped through the grout pipe, out the bottom of the casing, and upward into the annulus.

After the first-stage cement has set, the depth to the top of the cement will be determined by geophysical logging and tagging. Subsequent cement stages containing blends of from 2 to 12 percent bentonite will then be pumped through two grout pipes installed in the annulus. The cement will be pumped to the ground surface for all injection well casings and intermediate monitor well casings. The 6-inch-diameter casing for the monitor well will be cemented only up to a depth of about 1,650 feet to provide for the open annulus monitoring zone described previously.

Geophysical Logging Program

Geophysical logs will be run in each pilot hole before it is reamed. These logs will be used to evaluate the hydrogeology of the strata penetrated by the exploratory hole. The casing setting depths will be determined and cement calculations prepared based on these logs. The proposed logging program for both the injection and monitor wells is shown in Table 3.5.1-5.

Hydrogeologic Testing

Tests will be performed in both the injection and monitor wells to determine the depth to the 10,000 mg/l TDS interface, the permeability and thickness of the confining sequence, and the transmissivity of the injection zone. Testing will include taking drill cuttings, water quality samples, and rock cores, and performing geophysical logging, packer tests, and injection tests. Background water quality samples will be sent to a certified laboratory for analysis and will be analyzed for parameters specified by FDER.

Drill Cuttings - A sample of the drill cuttings will be taken every 10 feet, or at a formation change, during drilling and a lithologic description prepared from them. The drill cuttings will be used in conjunction with the geophysical logs to determine

Table 3.5.1-5
GEOPHYSICAL LOGGING PROGRAM

Injection Wells	Interval (feet)	Geophysical Logs
12-inch Pilot Hole	±0 to 500	LSN, GR, CAL
12-inch Pilot Hole	±500 to 1,850	CAL, GR, IL, FM-p, TEMP-s, FLRES-s, SON
12-inch Pilot Hole	±1,850 to 3,300	CAL, GR, IL, FM-p, TEMP-s, FLRES-s, SON
26-inch Reamed Hole	±1,850 to 2,750	CAL
16-inch Cemented Casing	±0 to 2,750	TEMP, CBL, GR
16-inch Casing and Open Hole	±0 to 3,300	TV, TEMP, CAL, RTS
10-inch Tubing	±0 to 2,750	TV, CAL
Monitor Well	**Interval (feet)**	**Geophysical Logs**
12-inch Pilot Hole	±0 to 500	LSN, GR, CAL
12-inch Pilot Hole	±500 to 1,200	LSN, GR, CAL
12-inch Pilot Hole	±500 to 1,600	LSN, GR, CAL, TEMP, FLRES
14-inch Casing	±0 to 1,600	CBL
12-inch Pilot Hole	±1,600 to 2,000	LSN, GR, CAL, TEMP, FLRES
6-inch Cemented Casing	±0 to 2,000	TEMP, CBL
6-inch Casing and Open Hole	±2,000 to 2,100	CAL, GR, ELEC

Key:

Key:	ELEC	Single-Point Electric and Spontaneous Potential
	CAL	Caliper
	GR	Gamma Ray
	LSN	Long and Short Normal Electric and Spontaneous Potential
	TEMP	Temperature
	FM	Flowmeter
	FLRES	Fluid Resistivity
	IL	Induction Log
	SON	Acoustic Velocity Log
	TV	Color Video Survey
	p	Pumping
	s	Static
	RTS	Radioactive Tracer Survey
	CBL	Cement Bond Log

Source: CH2M Hill, 1990

the depths at which each formation is encountered and to characterize the formations.

Rock Cores - The confining beds above the injection zone will be cored to characterize their lithology and hydraulic properties. Five cores will be obtained during drilling of the 12-inch-diameter pilot hole for the injection well. The cores will be obtained using a 10-foot-long core barrel. Representative portions of the cores will be sent to a geotechnical lab for determination of the vertical and horizontal coefficients of permeability and porosity. Laboratory results and the lithologic descriptions will be compared to the geophysical logs for confirmation of the confining nature of the beds overlying the injection zone.

Packer Testing - Straddle packer testing is proposed in the lowermost confining sequence to isolate a discrete interval in the confining zone and to test its hydraulic characteristics. Packer testing intervals will be selected after reviewing the cores and cuttings, the geophysical logs of the pilot hole, and the drilling rate. Dual inflatable packers will be set across the selected interval to be tested and the interval pumped while water levels are recorded. Time-drawdown curves will be prepared and the transmissivity of the tested interval will be calculated. Packer tests will also be run in the injection well to identify the base of the USDW and to help select the lower monitoring zone.

Injection Test - After installing the 16-inch-diameter casing, an injection test will be run to evaluate the hydraulic characteristics of the injection well. Brackish water from the monitor well will be used for the injection test. The injection rate in the 16-inch-diameter casing will be increased incrementally from 1,000 gpm to approximately 3,000 gpm, the duration of the test being approximately 8 to 12 hours. The maximum injection pressure and static head will be measured and the injection pressure caused by the formation will be calculated.

After installing the tubing and packer, a second injection test will be performed. The injection rate will be incrementally increased from 250 to 1,725 gpm.

Mechanical Integrity Testing

Tests to demonstrate the initial mechanical integrity of the injection wells will be run before the wells are placed in operation. The demonstration will be in two parts, the first requiring a showing that the casing has no leaks, and the second that no injected fluid can leak up around the outside of the casing into a USDW.

The integrity of the 16-inch-diameter casings will be demonstrated with a casing pressure test, which requires that 1.5 times the injection pressure be maintained for 1 hour with less than a 5-percent pressure drop. The absence of fluid movement behind the casings will be demonstrated with a radioactive tracer survey to satisfy the second part of the mechanical integrity demonstration. The 8-inch-diameter tubings will be pressure tested after installation by an annular pressure test.

Water Quality Testing

The water quality profile at the site will be developed through several means of data collection. Two primary purposes of water quality testing are to determine the depth to the 10,000 mg/l TDS interface and the background water quality of the injection and monitoring zones.

Reverse-air water samples will be collected every 30 feet while drilling the pilot hole in the injection and monitor wells. These samples will be analyzed in the field for temperature, specific conductance, and chloride concentration, and the results will be used to help define the 10,000 mg/l TDS interface. Water quality samples from the pilot hole packer tests also will be used to identify the base of the USDW and the water quality in the confining zone.

Background water quality samples of the injection and monitor zones will be taken. Water quality samples will be taken after the final casing is set and the well is developed to determine the background quality of the injection zone.

The monitoring zone will be allowed to flow for several days upon completion of construction to flush out all non-native water. To establish the background water quality in the monitoring zones, samples will be collected from the zones before injection begins and will be analyzed for the parameters shown in Table 3.5.1-6. The pre-injection monitoring zone water levels will also be measured to establish natural background water levels and fluctuation in the monitoring zones.

Characterization of the Injected Fluid

Volume

The volume of fluid to be injected will vary with the source of water used to supply the plant. When the Taylor Creek/Nubbin Slough source is used, a maximum injection volume of approximately 250 gpm will be generated. When the Floridan aquifer source is used, a maximum volume of approximately 1,280 gpm will be generated.

Chemistry

When using the primary source of water makeup for the plant, the wastewater disposed of via the injection well is only cooling tower blowdown. All process wastewater from the plant is reused as lime slurry dilution water for the spray dryer. When using the backup sources of water for the plant, the wastewater disposed of via the injection well is a mixture of cooling tower blowdown and excess process wastewater that cannot be reused. As discussed in Section 3.6, the wastewater from this facility is expected to be non-hazardous. Table 3.5.1-7 is a summary of the estimated wastewater quality from the raw water sources. The cooling tower blowdown will also contain some sulfuric acid and chlorine because these compounds are injected in the tower basin to control scaling, pH, slime, and algae growth. The pH of the wastewater will be maintained by adjustment during the treatment process.

Table 3.5.1-6
PARAMETER LIST FOR ESTABLISHING BACKGROUND WATER QUALITY

Primary Drinking Water Standards	Secondary Drinking Water Standards
Arsenic	Chloride
Barium	Color
Cadmium	Copper
Chromium	Corrosivity
Fluoride	Fluoride
Lead	Foaming agents
Mercury	Iron
Nitrate (as N)	Manganese
Selenium	Odor
Silver	pH
Sodium	Sulfate
Endrin	Total dissolved solids
Lindane	Zinc
Methoxychlor	
Toxaphene	Others
2,4-D	
2,4,5-TP, Silvex	Calcium
Total trihalomethanes	Magnesium
Trichloroethene	Potassium
Tetrachloroethene	Ortho phosphate as P
Carbon tetrachloride	Total phosphorus as P
Vinyl chloride	Hardness, total
1,1,1-trichlorethane	Specific conductivity field
1,2-dichloroethane	Total organic carbon
Benzene	Specific gravity
Ethylene dibromide	Bicarbonate
p-dichlorobenzene	Carbonate
1,1-dichloroethene	Nitrite nitrogen as N
Turbidity	Ammonia nitrogen as N
Coliform bacteria	Total kjeldahl, nitrogen as N
Radionuclides	

EPA Methods 608, 624, 625

Source: CH2M Hill, 1990

Table 3.5.1-7
ESTIMATED WASTEWATER EFFLUENT QUALITY

Parameter	Cooling Water Source: Taylor Creek/ Nubbin Slough (mg/l)	Cooling Water Source: Floridan Aquifer (mg/l)
pH	6 - 9	6 - 9
Alkalinity (as $CaCO_3$)	153	118
Total Dissolved Solids	3240	14800
Silica	25	17
Calcium	103	285
Magnesium	26	207
Sodium	994	4820
Potassium	61	96
Iron	0.73	<0.06
Sulfate	1095	1480
Chloride	832	7700
Fluoride	-	3.2
Nitrate	3.4	-
Phosphate	1.9	<2.3

Note: Concentrations are in mg/l of the ion.

Source: Bechtel, 1990

Compatibility

The proposed fluids to be injected must be compatible with the injection zone rock material and the formation fluids contained within the pores of that rock material. Injected fluids incompatible with the formation fluids can cause plugging or may chemically react with the formation material, causing detrimental effects to the injection or confining strata. A fractured and cavernous injection zone precludes the need to remove suspended solids to within the range of 1 to 5 mg/l. Based on other high TDS wastewaters injected in south Florida and the fractured and cavernous nature of the injection zone, wastewater from the ICL facility is expected to be compatible with the formation and formation fluids.

Injection System Operation and Monitoring Plan

Injection system monitoring data will be collected to provide a record of system performance and to detect any movement of injected fluid into the USDW. The injection system monitoring plan will consist of monitoring the injection well capacity and the injection flow rate and pressure, the annular fluid tank levels, the water elevation in the upper and lower monitor zone, and the water quality of the two monitoring zones (Table 3.5.1-8).

Contingency Plan

Each of the two injection wells will have the capacity to accept the maximum anticipated wastewater flow. If one of the wells is out of service, the second well will be used for injection. This will provide 100 percent redundancy in the injection well system for reliability, maintenance, and testing.

Injection Well Operational Monitoring

Injection well operational monitoring will consist of continuous recording, indicating, and totalizing the injection flow rate, and reporting the total daily flow, monthly average flow, monthly maximum flow, and monthly minimum flow. The injection pressure will be recorded, indicated, and totalized, and daily minimum and maximum and average pressure (psig) will be reported (Table 3.5.1-8).

Table 3.5.1-8
MONITORING PARAMETERS
ICL FACILITY

Monitoring Station	Parameter	Frequency
Injection Well	Flow	Continuous
	Pressure	Continuous
Monitoring Well	Pressure/water level	Continuous
	Conductance	Monthly
	Chloride	Monthly
	Standard complete chemical	Annual
Wastewater	pH	Weekly average
	TDS	Weekly average

Source: CH2M Hill, 1990

Continuous water level monitoring of the annular fluid between the tubings and the final casings will be provided, with an alarm for low level warning. Detection of leaks from the tubing, packer, or casing will be provided with this monitoring system.

On a quarterly basis, a specific injectivity test will be run on the active injection well. This test will evaluate the injection capacity of the well to detect any changes over time caused by plugging or other flow-restricting conditions. This test will typically require the well to be out of service for less than 15 minutes.

Monitoring Well Operational Monitoring

Every month, water quality samples will be collected from the two monitoring zones in the monitoring well and tested for comparison with the pre-injection water quality to detect changes caused by possible migration of the injected effluent. The samples will be collected after flowing a minimum of two casing volumes from both zones. The fluid produced from the monitor well will be pumped to the wastewater collection tank, from where it will be pumped into the injection well. The expected parameters to be analyzed for on a monthly basis are presented in Table 3.5.1-8.

In addition, continuous water level monitoring of the two monitoring intervals will be provided by recorders. Daily minimum and maximum levels and monthly minimum and maximum levels will be reported, along with the water quality data, on a monthly basis to the FDER.

<u>Conclusions</u>

Based on the literature and data from several operating injection wells in the vicinity of the proposed ICL facility, Class I well injection is feasible at this site. The injection zone used throughout south Florida for similar systems is expected to be encountered at a depth of approximately 2,900 feet. Adequate confinement is also expected to be demonstrated.

The conceptual design of the injection wells is dependent upon the type of material used for the tubing, as tubing material dictates tubing and subsequent casing sizes. Two injection wells with 10-inch-diameter FRP tubings and 16-inch-diameter final casings are anticipated at the ICL facility.

3.5.2 DOMESTIC/SANITARY WASTEWATER

Domestic/sanitary wastewaters are generated by wash basins, showers, toilets, water fountains, emergency showers and eyewash stations, etc. All sanitary wastewater generated at the ICL site will be transferred to the Indiantown Company water services sewer connection. The 2,300 gpd wastewater is less than 1 percent of the Indiantown Company's design capacity of 1.0 MGD. The existing daily flow is 0.41 MGD, therefore, no impact from the ICL facility is anticipated. There is no onsite treatment of sanitary wastewater.

3.5.3 POTABLE WATER SYSTEMS

Potable/drinking water for wash basins, showers, toilets, etc., is supplied via a connection to the Indiantown Company water services supply main. The Indiantown Company water service is designed for 1.30 MGD, while the average daily flow is 0.67 MGD. Therefore the ICL plant's requirements of 2300 gpd will have no impact on the available water supply. There is no onsite treatment to provide potable water.

3.5.4 PROCESS WATER SYSTEM

3.5.4.1 General

The primary source of process water for the ICL plant is surface water from TC/NS. During periods of extended drought when water is not available from TC/NS, process water will be obtained from a mixture of TC/NS water (from the cooling water storage pond) and groundwater from the upper production zone of the upper Floridan aquifer. Water qualities for the TC/NS and upper and lower production zones of the upper Floridan aquifer are provided in Table 3.5.0-1.

Process water is treated to meet the different water quantity and quality demands in the plant. Process water demands for large component cleaning such as air heater and boiler fireside and tube side cleaning occur when the plant is in an outage and are met with the treatment system augmented by the filtered water storage tank. Fire protection water is supplied from the cooling water storage pond. The process water treatment scheme and flowrates are shown in Figures 3.5.0-3 and 3.5.0-4 for the primary and backup water sources, respectively.

3.5.4.2 Process Water Demand/Uses

Filtered and demineralized water is used to meet the following plant water demands:

- Spray dryer lime slaking water is used to dissolve the lime used in the flue gas desulfurization system. The slaked lime is further diluted with reclaimed wastewater (as discussed in Section 3.6.2) prior to injection into the spray dryer.

- Filtered service water is provided throughout the plant for washdown purposes, pump and equipment gland seal flushes, dust suppression in the coal handling area, manganese greensand and activated carbon filter backwashes, demineralizer regeneration, and dilution at chemical feed stations. The service water flow shown on Figure 3.5.0-4 is higher than the demand shown on Figure 3.5.0-3 to account for the significantly higher demand for lime and soda-ash slaking water at the sidestream softener when using the lower production zone of the upper Floridan Aquifer as the source of cooling water makeup.

- Demand for demineralized water in the plant consists of boiler makeup, ion-exchange resin regeneration, makeup of export steam losses, and other miscellaneous uses.

3.5.4.3 Process Water Treatment

With one exception, the use of TC/NS as the primary makeup water source dictates the approach to process water treatment for the plant. The equipment is then sized to accommodate use of the mixture of TC/NS water and groundwater from the upper production zone of the upper Floridan aquifer as a backup process water source. The exception (discussed in greater detail below) is that a reverse osmosis unit is utilized when using the backup sources of process water.

The following typical treatment description applies to either water source, unless otherwise noted. Raw process water is first chlorinated to destroy color, organics, bacteria, etc. Only the iron levels in the two sources precludes direct use of the water as service water. Therefore, the chlorinated water is pumped through a manganese greensand filter. The manganese greensand filter removes iron and manganese from the raw water and filters out suspended solids. Potassium permanganate solution is added continuously to regenerate the greensand filter bed which in turn oxidizes the iron and manganese. The iron and manganese precipitates are trapped in the filter, along with other suspended solids, and transferred to the wastewater equalization tank when the greensand filter is backwashed. The filtered effluent has a suspended solids level of less than 1 mg/l.

The filtered water is stored in the filtered water storage tank to provide for demands such as demineralizer makeup, plant service water, and spray dryer lime slaking water.

Water that requires demineralization is pumped from the filtered water storage tank through an activated carbon filter. The activated carbon filter removes residual chlorine and adsorbs organics. The activated carbon filter requires periodic backwashing. The backwash is transferred to the wastewater equalization tank.

When using the primary process makeup water source, product water from the activated carbon filter is transferred directly to the demineralizer system. However, as shown in Table 3.5.0-1, the sodium and chloride levels in the groundwater from the upper production zone of the upper Floridan aquifer are very high, and would place a significant burden on the demineralizer. Therefore, a reverse osmosis unit is used to treat the process makeup water when using the backup process water source. The reverse osmosis unit uses a high pressure differential to force water through a membrane, separating the dissolved ions from the water. Brine from the reverse osmosis unit is transferred to the injection well. Product water from the reverse osmosis unit is transferred to the demineralizer system.

The demineralizer system consists of two parallel trains, each with a strong cation, strong anion, and polishing mixed beds. The mixed bed has both anion resin and cation resin to remove residual ions. The return condensate from the Caulkins plant is treated in the mixed bed unit to remove ions picked up from the piping and leaks in the system. For this reason, the mixed bed units are sized substantially larger than the primary beds.

The demineralizer resin beds are exhausted by the ions in the water being treated. The demineralizer beds are regenerated periodically with acid (cation beds) or caustic (anion beds). The regeneration waste stream consists of a backwash, an injection of acid or caustic to restore the resin capacity (the actual regeneration process), a slow rinse, and a fast final rinse to remove excess regenerant. Wastes from demineralizer regeneration are transferred to the neutralization tank for treatment.

Demineralized water is stored in the condensate storage tank. Water for boiler makeup, demineralizer regeneration, etc., is withdrawn from this tank.

3.6 CHEMICAL AND BIOCIDE WASTES

Operation of the Indiantown Cogeneration, L.P. (ICL) project requires the use of chemicals to treat or condition water, and results in the generation of wastewaters. These wastewaters are collected, treated, reused, or discharged. Figures 3.5.0-3 and 3.5.0-4 show the wastewater treatment equipment and average annual flows when using the two different plant makeup water sources.

The objective of the wastewater treatment scheme is to control pH, oil, and suspended solids levels; then discharge the wastewater to the Boulder Zone of the lower Floridan aquifer via an injection well (See Section 3.5.1.5).

Two wastewater streams are recycled within the plant. Boiler blowdown has a low total dissolved solids level and is recycled to the cooling tower sidestream softener. Runoff and leachate from the inactive coal pile is also recycled to the cooling tower sidestream softener. In addition, a portion of the plant wastewater is used as spray dryer lime slurry dilution water.

A summary of maximum daily, maximum monthly, and average annual wastewater discharges to the Boulder Zone of the lower Floridan aquifer when using the primary and backup sources of water is presented in Table 3.6.0-1. The wastewater effluent quality for the average annual conditions when using the primary water source and the wastewater effluent quality for the maximum daily conditions when using the backup water sources are presented in Table 3.6.0-2.

Table 3.6.0-1
SUMMARY OF PROJECT WASTEWATER DISCHARGES

Case:	Maximum Daily (MGD)	Maximum Monthly (MG/Mo)	Average Annual (MGY)
Primary Source of Water	0.426	12.3	137
Backup Sources of Water	1.84	52.9	154

Notes:

1. Wastewater from the ICL plant is discharged to the Boulder Zone of the lower Floridan aquifer via an injection well.
2. Maximum daily discharge flows are based on design flows through the cooling tower and 100 percent load factor for 24 hours.
3. Maximum monthly discharge flows are based on the highest average monthly flows through the cooling tower at 100 percent load factor for 31 days.
4. Average annual wastewater flows when using the primary water source are based on the annual average flows through the cooling tower at 100 percent load factor for 365 days. Average annual wastewater flows when using the backup water sources are based on the annual average flows through the cooling tower at 100 percent load factor for 3 months.

Source: Bechtel, 1990

Table 3.6.0-2
SUMMARY OF PROJECT WASTEWATER QUALITY

Parameter	Primary Water Source (mg/l)	Backup Water Source (mg/l)
pH	6-9	6-9
Total Dissolved Solids	3,240	14,800
Total Hardness (as $CaCO_3$)	364	1,560
Oil/Grease	<15	<15
Residual Chlorine	<1.0	<1.0
Alkalinity (as $CaCO_3$)	153	118
Silica	25	17
Calcium	103	285
Magnesium	26	207
Sodium	994	4,820
Potassium	61	96
Iron	0.73	<0.06
Sulfate	1,095	1,480
Chloride	832	7,700
Fluoride	-	3.2
Nitrate	3.4	-
Phosphate	1.9	<2.3

NOTES:

1. Concentrations are in mg/l of the ion.
2. The wastewater effluent quality for the primary water source (Taylor Creek/Nubbin Slough) is based on average annual flows through the water and wastewater treatment system. These flows are based on the average annual meteorological conditions for the cooling tower, 100 percent load factor and 24 hours per day for 365 days. The cooling tower operates at 10 cycles of concentration.
3. The wastewater effluent quality for the backup water source (lower production zone of the upper Floridan aquifer for cooling water makeup and mixture of Taylor Creek/Nubbin Slough and upper production zone of upper Floridan aquifer for process water makeup) is based on maximum daily flows through the water and wastewater treatment system. These flows are based on design meteorological conditions for operation of the cooling tower and 100 percent load factor for 24 hours. The cooling tower operates at 3.5 cycles of concentration.

Source: Bechtel, 1990

3.6.1 PLANT CHEMICAL AND BIOCIDE USE

A variety of chemicals and a biocide are used in the plant to obtain or maintain a desired quality of water as part of cooling water treatment, process water treatment, boiler water treatment, and wastewater treatment.

3.6.1.1 Chemical Use in Cooling Water Treatment

Cooling water is treated to control corrosion, scaling, and biofouling. These three processes are intertwined and, over a period of time, lead to heat transfer efficiency losses in both the condenser and cooling tower, adversely affecting the heat rate of the plant. Chemicals are used to control these processes. In addition, chemicals are used in the sidestream softener to allow the cooling tower to operate at higher cycles of concentration.

Scale is controlled by adding a polymeric form of organic phosphates. A residual of a few mg/l of a high molecular weight polymer keeps ions in suspension, preventing them from depositing on the heat transfer surfaces. There are a variety of anti-scalants available for cooling water treatment applications.

Corrosion inhibitors are added to control the formation of metal oxides on heat transfer surfaces. These inhibitors are non-metal based (unlike zinc and chromium based corrosion inhibitors of the past); therefore, the corrosion inhibitors do not add metals to the cooling tower blowdown.

Sulfuric acid is added to the circulating water to prevent the pH from rising above about 8.3. Sulfuric acid also converts calcium carbonate to calcium sulfate which has a much higher solubility and does not form scale on heat transfer surfaces.

The circulating water is chlorinated with sodium hypochlorite to kill bacteria and destroy organics which have the potential to foul the condenser and grow on the grid in the cooling tower. The sodium hypochlorite may be either fed into the cooling tower basin or injected at the inlet to the condensers. The consumption (or chlorine demand) exhibited by the cooling water depends on the number of organisms in the cooling water, the degree of biological fouling of the condenser tubes, and the amount of ammonia in the cooling water. The rate, frequency, and duration of chlorination will be set by the operator in response to anticipated seasonal variations in these parameters and review of condenser performance to maintain adequate control without over-chlorinating.

Chlorination is only required for up to 2 hours per day. Free residual chlorine levels in the cooling tower blowdown are expected to be less than 1.0 mg/l.

As discussed in Section 3.5.1.1, a portion of the circulating water is passed through a sidestream softener to reduce hardness, silica, iron, manganese, organics, etc. In the sidestream softener, lime and soda-ash (sodium carbonate) are added to the water. This causes calcium carbonate, magnesium hydroxide, and ferrous hydroxide to precipitate out of the solution. Organic polymers are added to assist in settling the suspended solids and precipitates to the bottom of the softener. The sludge from the clarifier is transferred to the wastewater sludge thickener, while the clarified effluent rejoins the circulating water.

With the exception of the chemicals removed as precipitates in the sidestream softener underflow and the decay of sodium hypochlorite, all other chemicals utilized in the cooling water treatment leave with the cooling tower blowdown.

3.6.1.2 Chemical Use in Process Water Treatment

As discussed in Section 3.5.4, raw process water is treated to produce the quality required by different plant demands.

The raw process water is chlorinated with sodium hypochlorite prior to entering a small surge tank at the front end of the treatment system (prior to the manganese greensand filter). The sodium hypochlorite is used to kill bacteria and destroy organics which have the potential to foul plant piping systems and ruin the ion-exchange resins in the demineralizer. Sodium hypochlorite is fed continuously to the raw water. The feed rate will be set by the operator in response to seasonal variations in organics levels in the raw water (especially from the Taylor Creek/Nubbin Slough source).

Iron is removed from the raw process water in a manganese greensand filter. The manganese greensand filter is regenerated either by a continuous or intermittent addition of a potassium permanganate solution to the process water upstream of the filter. The feed rate of potassium permanganate will be based on the iron and manganese content of the raw water. Excess potassium permanganate, beyond that required for iron and manganese removal, oxidizes other constituents in the raw water, such as organics or microorganisms. The potassium is ionized in the water, while the manganese in the permanganate forms insoluble manganese hydroxide and is removed by the filter.

The reverse osmosis unit will be used when the backup sources of process water are needed. The membranes of the reverse osmosis unit will require occasional acid cleaning (possibly as often as once per week when in use) to remove accumulated scale. The wash water will be directed to the neutralization tank.

The ion-exchange resins in the demineralizer beds require periodic regeneration. Sulfuric acid is used to regenerate the strong cation bed. Sodium hydroxide is used to regenerate the anion bed. The acidic and alkaline waste streams are transferred to the neutralization tank after passing through the beds.

3.6.1.3 Chemical Use in Boiler Water Treatment

Even though process water is treated to meet the boiler feedwater quality requirements, boiler water undergoes chemistry changes and acquires metals as it circulates through the steam cycle piping. Therefore, chemicals are added to maintain a desired water quality, to prevent corrosion and scaling in the steam cycle piping.

A sodium phosphate compound is injected into the boiler water to react with the hardness ions and form an insoluble compound called hydroxyapatite, which remains in suspension until it is removed in the boiler blowdown.

Phosphate based polymers, which keep the precipitates formed in suspension by modifying their structure, are added to the boiler water in a solution form. The suspensions are light weight and are flushed out with the boiler blowdown.

Neutralizing amines, which are nitrogen containing organic compounds, are added in the steam cycle. These amines are volatile in nature and provide pH control in the steam piping as well as the return condensate loop.

Passivating amines are also nitrogen containing organic compounds which, when introduced to the steam cycle, form a passivating (inert) film on the steam piping internals to help control corrosion of the boiler system.

Dissolved oxygen in the boiler water (which leads to corrosion of the boiler tubes) is controlled by the use of an oxygen scavenger. The chemical used is hydrazine or an equivalent. Hydrazine forms water and molecular nitrogen in controlling dissolved oxygen. The nitrogen is removed in the deaerator.

3.6.1.4 <u>Chemical Use in Wastewater Treatment</u>

Wastewater from demineralizer regeneration and chemical lab drains that may not have a neutral pH are directed to the neutralization tank where sulfuric acid or sodium hydroxide are used to adjust the pH to between 6 and 9.

Coagulants and filter aids are used in the wastewater treatment clarifier to aid in removing suspended solids from the plant effluent and in dewatering the resultant sludge. Coagulant aids and filter aids are high molecular weight compounds that overcome the electrical charges which cause suspended particulates to repel one another. The dose is usually between 0.5 to 2 mg/l, and is optimized once the plant is in operation. Coagulant aids are added to the sludge thickener to produce a sludge with a higher solids content that dewaters more easily. Filter aids are used in the filter press for a better solids capture and to produce a clearer filtrate. These organic chemicals are removed with the dewatered sludge (filter cake).

Lime is used to adjust the pH of the runoff and leachate from the inactive coal pile before it is recycled to the cooling tower sidestream softener.

3.6.2 WASTEWATER TREATMENT DESCRIPTION

The objective of the wastewater treatment scheme is to control pH, oil, and suspended solids levels; then discharge the wastewater to the Boulder Zone of the lower Floridan aquifer via an injection well. Figures 3.5.0-3 and 3.5.0-4 show the wastewater treatment equipment and average annual flows when using the two different plant makeup water sources.

Section 3.5.1.5 discusses the compatibility of the injected fluids with the injection rock zone material. The wastewater to be injected is expected to be compatible with the formation and formation fluids of the Boulder Zone of the lower Floridan aquifer. The quality of the wastewater based on average annual flows using the primary source of water is presented in Table 3.6.0-2. The "worst case" effluent quality at design flow rates using the backup sources of water is also presented in Table 3.6.0-2. No hazardous materials may be injected into the well. Therefore, measures (e.g., oily water separators, good operational practices, training of personnel, dikes around chemical treatment areas, etc.) will be taken to ensure that hazardous solvents, degreasers, or other chemicals that may be used at the plant will not enter the floor drains or equipment drains connected to the wastewater equalization tank.

The use of the spray dryer as the flue gas desulfurization system provides an opportunity to dispose of wastewater in the spray dryer. The lime slurry dilution water can tolerate higher total dissolved solids levels than is found in the service water. Therefore wastewater is used to meet this demand.

When using the primary source of water for plant makeup, the wastewater flow from the plant (excluding cooling tower blowdown) does not provide sufficient quantity to meet the spray dryer dilution water demand. Therefore, cooling tower blowdown is used to supplement wastewater from the wastewater treatment clarifier. However, when using the backup water sources, the wastewater flow (again excluding cooling tower blowdown) is sufficient to meet the spray dryer dilution water demand. The cooling tower blowdown when using the lower production zone of the upper Floridan aquifer for cooling water makeup is actually unsuitable for use as spray dryer dilution water because of the very high total dissolved solids and sulfate levels.

A small portion of the total steam flow is discharged from the boiler as a liquid blowdown to maintain a solids balance in the boiler water. This waste stream contains dispersants, phosphates, and trace amounts of iron and copper picked up from piping and equipment surfaces. Blowdown from the boiler is at an elevated temperature and pressure. A flash tank recovers a very pure vapor with a low total dissolved solids level which can be recycled directly to the boiler water deaerator (after recondensation). The boiler water treatment chemicals remain with the blowdown. The blowdown stream is recycled to the cooling tower sidestream softener.

The acidic and alkaline waste streams from demineralizer regeneration are transferred to the neutralization tank. Other plant waste streams with the potential of being acidic or basic, such as chemical lab drains, are also directed to the neutralization tank. In the tank, the acidic and caustic streams neutralize one another to a certain extent. Sodium hydroxide or sulfuric acid are used to adjust the final pH to between 6 and 9. The neutralized flows are then transferred to the wastewater equalization tank.

Brine reject from the reverse osmosis unit has a very high total dissolved solids level. The brine does not require pH adjustment or suspended solids removal; therefore, it is transferred directly to the wastewater collection tank at the injection well.

Equipment within the power block and the vicinity, such as transformers and motors, may contribute oil in small amounts during equipment washes. Potential oily wastes from floor drains are treated in an oil/water separator which uses the difference in specific gravity between oil and water to effect the separation. The cleaned water is transferred to the wastewater equalization tank. The collected oil is held for disposal offsite by a licensed waste oil handler.

Periodically, the manganese greensand filter and activated carbon filter are backwashed to clean the filter media. The backwashes have a high suspended solids level and are transferred to the wastewater equalization tank.

Wastewater flows from the neutralization tank, oil/water separator, and filter backwashes are collected in the wastewater equalization tank to provide uniform flow and strength before being treated. The wastewater is then transferred to a wastewater treatment clarifier where it is mixed with a coagulant aid to assist in settling suspended solids. The underflow from the clarifier is transferred to the sludge thickener.

When the plant is operating using the primary water source, the clarified effluent is mixed with cooling tower blowdown, and a portion is used to meet the spray dryer dilution water requirements. The remaining wastewater is transferred to the wastewater collection tank at the injection well.

When the plant is operating using the backup water sources, the clarified effluent alone is used to meet the spray dryer dilution water demand. The excess clarifier effluent is transferred to the wastewater collection tank at the injection well.

The wastewater collection tank at the injection well serves as a surge tank for the well pumps. The collected water is injected into the Boulder Zone of the lower Floridan aquifer.

Underflow from the wastewater treatment clarifier and the sidestream softener underflow is transferred to a sludge thickener. The sludge thickener further concentrates the suspended solids by gravity. The result is a very low volume of thickened sludge which is next sent to a filter press for dewatering. The supernatant from the sludge thickener is recycled to the wastewater treatment clarifier.

When the primary plant water source is being used, the filter press processes all of the sludge generated during the day during a single shift. However, a much larger quantity of sludge is generated when the backup plant water sources are used, requiring the filter press to be operated two shifts per day. A sludge holding tank is used upstream of the filter press to store the sludge. The filter press processes the thickened sludge to yield a cake of 35 to 50 percent solids by dry weight. Conditioning chemicals are usually added for better cake yield. The filtrate from the filter press is returned to the wastewater treatment clarifier, while the cake is taken offsite to an approved landfill for disposal.

Periodically, major equipment such as the air heater and the boiler tubes (fireside and tubeside) require cleaning to restore heat transfer areas. A large quantity of filtered water is used to flush the equipment, followed by use of chelating agent and acid cleaning or other similar process to dislodge and remove scale and corrosion products accumulated while the component was in service. Proprietary chemicals used for cleaning and the final cleaning agent are usually alkaline solutions. Such equipment cleaning will be performed by an outside vendor during a plant outage. Initial flush and final rinse waters will be transferred to the neutralization tank, as these wastewater streams are not strongly acidic or basic and do not contain high levels of metals. The wastewater from the actual acid cleaning and first rinse will be transported offsite for disposal by the contractor.

The inactive coal storage area is lined to prevent seepage of leachate into the groundwater. The storage area is grassed over to prevent fugitive particulate emissions and minimize impacts on runoff quality. Runoff and leachate from the inactive coal storage area are collected in a lined drainage ditch and directed to the coal pile runoff basin. The coal pile runoff basin is also lined to prevent seepage. Runoff and leachate are treated with lime in a flash mixing tank at the entrance to the runoff basin. The lime is used to adjust the pH of the runoff and leachate. The runoff basin serves as a surge tank and settling pond. The pH adjustment in the flash mixing tank causes some heavy metals to precipitate out and settle in the basin with the suspended solids. The contents of the coal pile runoff basin are transferred to the cooling tower sidestream softener at a controlled flow rate. The relatively small peak flow rate at which the runoff stream is mixed into the circulating water minimizes the impact on the cooling tower operation. The lime and soda ash addition in the sidestream softener also ensures that the quality of the runoff stream is acceptable for incorporation with the circulating water.

3.7 SOLID AND HAZARDOUS WASTE

3.7.1 SOLID WASTES

3.7.1.1 General

The Indiantown Cogeneration, L.P. (ICL) project facility will generate solid waste from the operation of the combustion system, water and wastewater treatment system, and flue gas cleaning system (FGC) which includes the SDA system and the baghouse. In addition, miscellaneous solid waste, such as general office refuse and maintenance wastes, will be produced. These wastes are quantified in Table 3.7.1-1.

The quantities and chemical constituents of the combustion system wastes (bottom ash and fly ash, including reaction products generated in the FGC system) are primarily related to the characteristics of the fuel. The maximum expected percentages of ash and sulfur content, as well as the minimum heating value of coal were assumed in the calculations of by-product/solid waste quantities and composition. These estimates should be considered worst-case estimates. Actual quantities are expected to be less during normal operation.

Water/wastewater system wastes are generated during the water pretreatment (softening, clarification, filtering), wastewater neutralization and clarification, and demineralizer resin replacement. The water/wastewater system wastes will take the form of a filter sludge cake. Demineralizer resins will need to be replaced periodically.

The amount of filter sludge cake generated by the water treatment system is dependent on which source of water is used for cooling and process water for the plant. Taylor Creek/Nubbins Slough will be used as the primary source of both cooling and process water. During these times, filter sludge cake generation is expected to be a maximum of 115 tons per month (about 1380 tons/year). During

Table 3.7.1-1
ICL FACILITY SOLID WASTE QUANTITIES

Source		Quantity	Disposal
Combustion Facility			
Bottom Ash	(tons/yr)	30,484[1]	Return to Mine
Fly Ash plus SDA Solids	(tons/yr)	283,150[1]	Return to Mine
Water/Wastewater Treatment			
Treatment Solids	(tons/yr)	3,435[2]	Offsite
Demineralizer Resin Beds	(yd^3/yr)	180[1]	Offsite
Miscellaneous Wastes			
Office Refuse	(yd^3/yr)	2,500	Offsite
Maintenance	(yd^3/yr)	100[1]	Offsite

(1) Assumes worst case of 100% capacity.
(2) Assumes worst case of 9 months per year using Taylor Creek/Nubbins Slough as water source and 3 months per year using Floridan aquifer as water source.

Source: Bechtel, 1990

drought conditions when the Taylor Creek/Nubbins Slough is not available, the Floridan aquifer must be used as the source of cooling water. Since the quality of water from this aquifer is not as good as the Taylor Creek/Nubbins Slough, a maximum of 800 tons per month of filter sludge cake is expected to be generated during drought conditions.

General office waste and maintenance waste are the typical consumable waste (paper, rags, etc.) found in any office or industrial facility.

3.7.1.2 Methods of Treatment, Handling, Interim Storage, and/or Disposal

Onsite Disposal

There will be no onsite disposal of solid waste.

Bottom Ash

Bottom ash is removed from the boiler hopper via a submerged drag conveyor. Bottom ash is transported by conveyor from the submerged drag conveyor to a silo sized for approximately 3 days' storage capacity. The bottom ash will be loaded from the silo into railcars for disposal at the coal mine.

Fly Ash and SDA Solids

Fly ash and SDA solids (ash) are conveyed to the recycle ash silo for addition to the lime slurry used in the flue gas cleanup system. When the recycle ash silo is filled, ash is bypassed to an ash storage silo having approximately 3 days' storage capacity. From the ash storage silo, the ash is loaded into rail cars with special covers (to prevent the generation of fugitive dust) for disposal at the coal mine.

Water/Wastewater

Operations of the water/wastewater treatment system will result in a nonhazardous sludge cake (from filter presses) composed primarily of calcium carbonates, hydroxides of metals (aluminum, magnesium), and inert solids. This filter cake will be placed in containers or bins and loaded on trucks for offsite disposal.

The nonhazardous wastes generated periodically from replacement of the demineralizer resin beds will be removed by their suppliers.

Miscellaneous

Miscellaneous office waste will be directed to licensed, offsite disposal areas. Spent air filters from the air inlet, damaged or used baghouse filter bags, etc., will be transferred to onsite storage-for-disposal areas prior to being transported to offsite disposal areas.

3.7.2 HAZARDOUS WASTE

Florida's hazardous waste management program is based on statutory provisions of Chapter 403 of the Florida Statutes and Rules, codified in F.A.C. Chapter 17-730. F.A.C. 17-730 tracks closely those regulations promulgated under 40 CFR Parts 260 through 266. These regulations address the identification and listing of hazardous waste, and apply to hazardous waste generators, transporters, and facility owners and operators.

3.7.2.1 Definition of Hazardous Wastes

A solid waste is a hazardous waste if it meets either of the following criteria:

- It exhibits any of the characteristics of hazardous wastes identified in 40 CFR 261 Subpart C.
- It is listed in 40 CFR 261 Subpart D.

Listed hazardous wastes are divided into five categories: non-specific sources, specific sources and discarded commercial products, off-specification species, container residues, and spill residues. Each listed hazardous waste has an EPA-assigned alphanumeric identifier.

3.7.2.2 Cogeneration Facility

The facility may generate both listed and characteristic wastes. Those wastes can be categorized as follows:

- Non-thermal waste

- Chemical product storage and transfer wastes (waste oils)

- Miscellaneous wastes

Non-Thermal Waste

The category of non-thermal wastes is broad, including various wastewaters resulting from operation of the facility. Although not hazardous by definition, these wastes can contain chemicals which make them hazardous. The following non-thermal wastes are produced:

- Wastewater treatment filter effluent

- Spent demineralizer regeneration solutions

- Boiler blowdown

- Demineralizer resin beds

- Metal cleaning wastes

The water/wastewater treatment effluent contains dissolved solids removed during water pretreatment (softening, clarification, filtering, and demineralizer solids treatment). Due to the absence of hazardous constituents in the raw process water, the water treatment effluent from the facility is not expected to be hazardous. This effluent is either used in the SDA system or injected through the deep well injection system.

Spent acidic and basic solutions that have regenerated the demineralizer resin bed ion exchangers will be routed to a neutralization tank for pH adjustment. Thus, these wastes will be treated to eliminate corrosivity. Since these wastes will be treated in a totally enclosed elementary neutralization unit, they will not represent hazardous wastes according to Florida Hazardous Waste Rules (F.A.C. 17-730). Once treated, these wastes will be either used in the SDA system or injected through the deep well injection system.

Though it may contain trace amounts of an oxygen scavenger, boiler blowdown represents a high quality stream which can be directed for use in the cooling tower system or injected in the deep well injection system.

The boiler tubes may require infrequent cleaning. This will involve application of an organic solution or nonhazardous citric acid solution (e.g., Citrosolv) to dissolve scale, followed by a water rinse and final application of a neutralizing alkali agent. The spent acid solution will be neutralized and recycled in the lime slaking system or injected into the deep well. The remaining spent chemical products and associated liquid wastes are termed metal cleaning wastes and may be hazardous. If corrosive only, these wastes may be pumped to the neutralization tank (totally enclosed elementary neutralization unit) and treated to render them nonhazardous. In the alternative, or if deemed hazardous under another criterion, these wastes would be collected and removed by a licensed contractor for offsite disposal.

Chemical Product Storage and Transfer Wastes

Chemical product storage and transfer operations at the proposed facility could result in infrequent waste generation. Accidental spills will be contained (bermed areas) and impacted areas will be thoroughly washed and rinsed. Dissolved and suspended solids, acids, alkalies, and oils will represent the primary constituents of the wastes generated. With the exception of oily wastes, these wastes will be directed to the wastewater treatment facility where they will be treated and discharged as filter cake and processed wastewater. The oily wastes will be separated from this collected runoff and will be recycled or disposed of by an approved contractor.

Miscellaneous Wastes

Generation or use of potentially hazardous materials (paint, thinners, solvents, etc.) will be minimized through the judicious use of less hazardous or nonhazardous materials or systems and through good housekeeping practices. If hazardous spent materials or wastes are generated, they will be stored in appropriate containers in segregated storage areas for a period not to exceed 90 days. These wastes will be treated or disposed of offsite by a licensed hazardous-waste contractor.

3.7.2.3 Permanent Onsite Disposal and Storage

Hazardous wastes, as defined by F.A.C. 17-730, will not be treated or disposed of onsite, and will not be stored onsite for a period in excess of 90 days or such other period as the regulations may allow.

3.8 SITE DRAINAGE

3.8.1 EXISTING SITE DRAINAGE

The topography of the Indiantown Cogeneration, L.P. (ICL) project site varies between El. 35.0 and 31.0 feet, with the higher elevations in general occurring along the northern and western periphery of the site. The existing grade for the power block areas, including switchyard and cooling tower, varies between El. 35.0 and 33.0 feet. The prevailing grade along the existing transmission line corridor varies between El. 35.0 and 33.0 feet. The area to the north of the transmission line corridor has an existing grade elevation of approximately 35.0 feet. Due to the relatively flat gradient and limited topographic relief, the stormwater runoff has a low flow velocity. Much of the site area is heavily vegetated with pine and wet prairie. A drainage ditch traverses the entire site from north to south carrying the site surface runoff, as well as surface runoff from areas north of the site, to the St. Lucie Canal approximately 2.5 miles away. In general, the site drains in a southerly direction toward the ditch.

The ICL site is characterized by several isolated, naturally occurring nonforested, fresh water wetlands interspersed over the site. The boundaries of these shallow, wet prairie wetlands, as shown on the Plot Plan (Figure 3.2.0-1), were developed from the field survey performed in the Spring of 1990.

3.8.2 DRAINAGE AREAS

The estimated areas for the developed ICL site, as shown on the Site Drainage Plan (Figure 3.8.2-1), are:

- Power block area: 21 acres
- Coal handling area: 9 acres
- Inactive coal storage area: 6 acres
- Cooling water storage pond: 25 acres

The other areas of the project not disturbed by development are:

- Wetland preserves, including ditch: 24.4 acres
- Existing transmission power lines: 8 acres
- Upland preserves, including wetland buffers: 58.3 acres
- Miscellaneous areas north and west of rail loop: 22.7 acres

For reference and further discussion purpose, these areas are defined as follows:

- Power Block Area:

  Includes areas housing turbine, boiler, water treatment system, administration building, stack, scrubbers and baghouse buildings, switchyard, various tanks, cooling tower, parking lot, oil storage tank, injection well, and three stormwater management basins.

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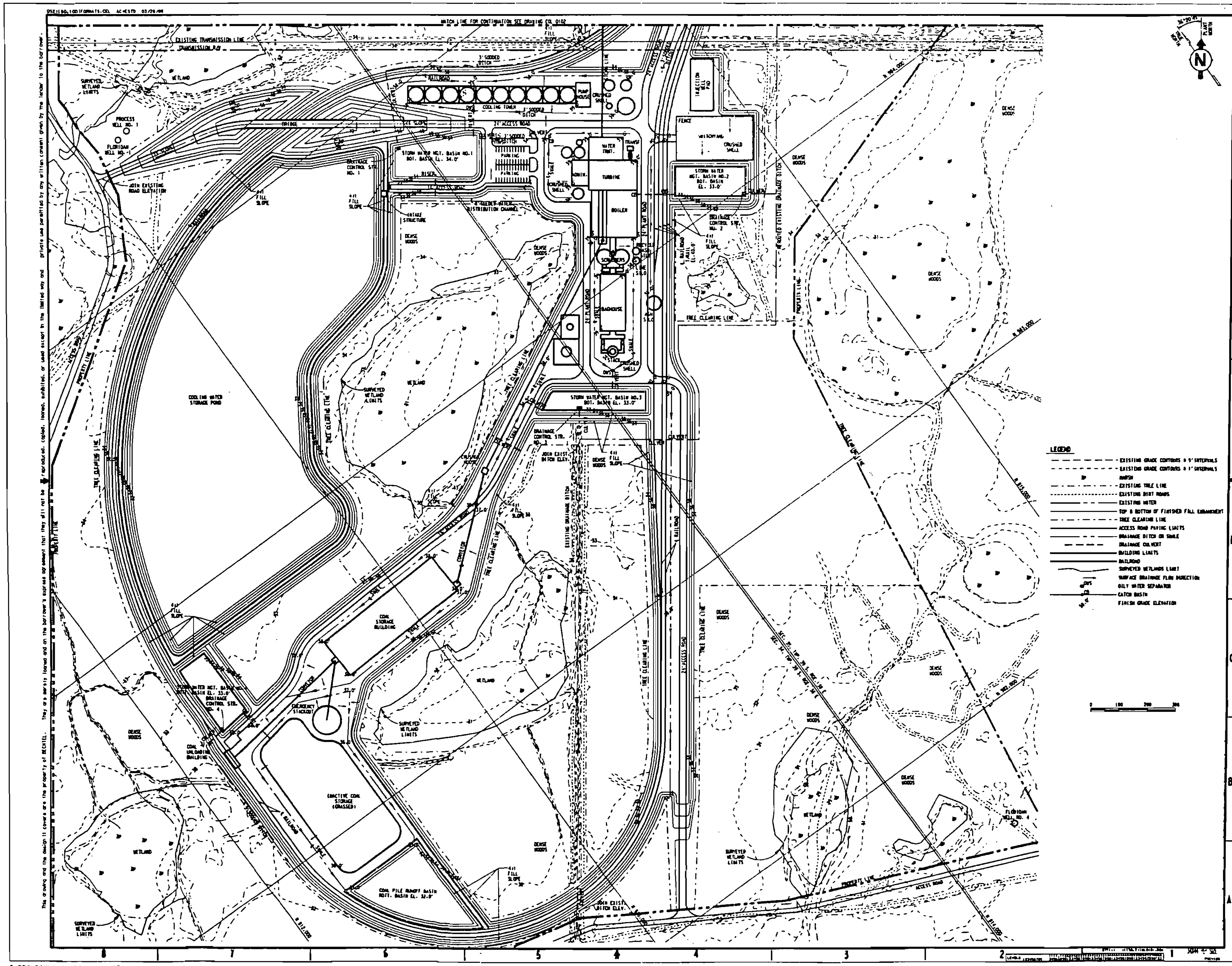

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Figure 3.8.2-1. (Sheet 1 of 2)

PRELIMINARY DRAINAGE PLAN

Source: Bechtel, 1990

INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

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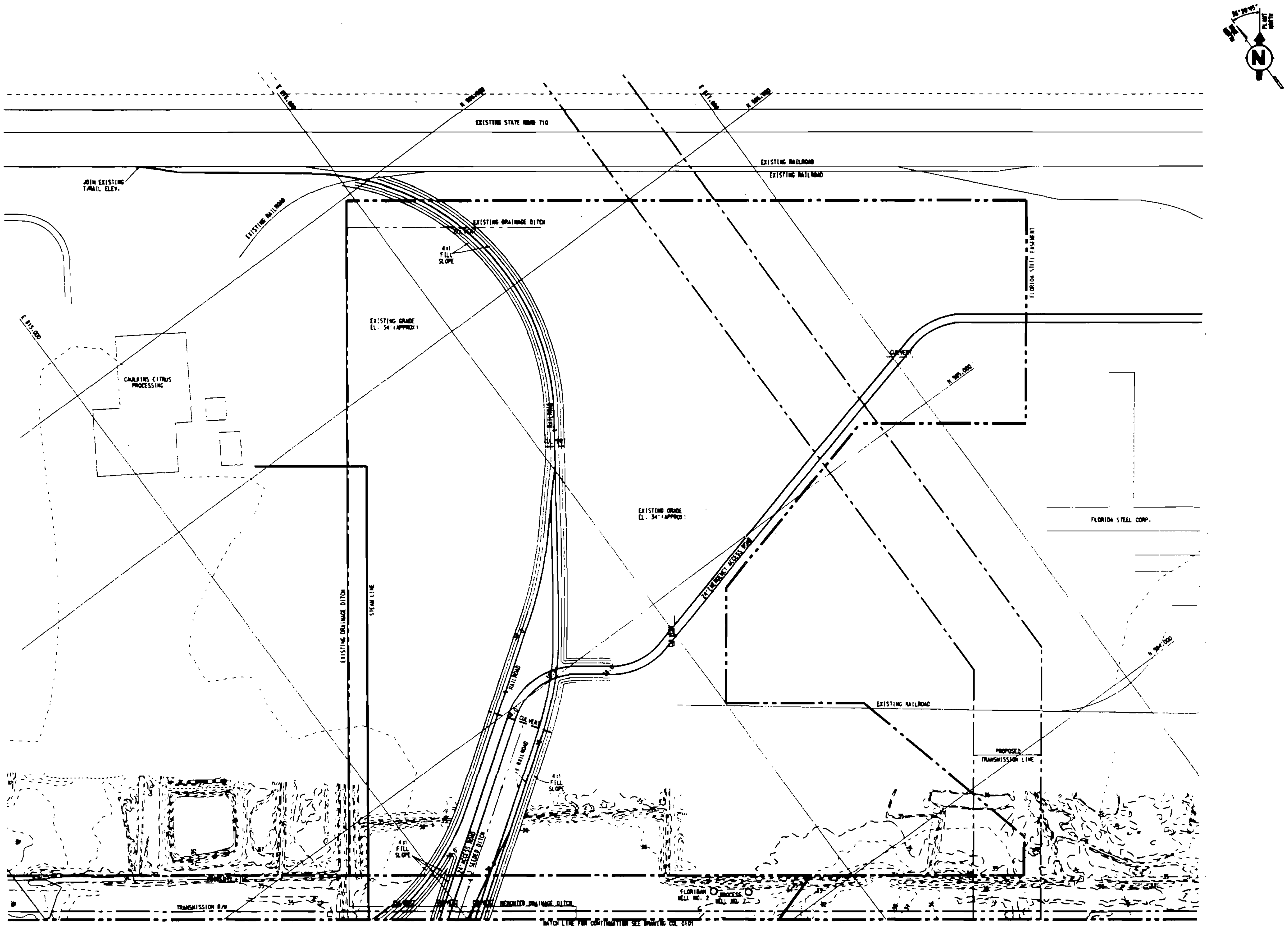


Figure 3.8.2-1. (Sheet 2 of 2)

PRELIMINARY DRAINAGE PLAN

Source: Bechtel, 1990

INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

- Coal Handling Area:

  Includes areas housing coal storage building, coal handling building, conveyors, and a stormwater management basin.

- Inactive Coal Storage Area:

  Includes areas dedicated to coal storage, emergency stackout, and coal pile runoff basin.

- Cooling Water Storage Pond:

  Includes area dedicated to the cooling water storage pond.

3.8.3 DESIGN CRITERIA AND APPLICABLE REGULATIONS

3.8.3.1 South Florida Water Management District Criteria

The surface water management system will be designed in accordance with the regulations and requirements of the South Florida Water Management District (SFWMD), which has been delegated authority under F.A.C. 17-25.090. These regulations and requirements are outlined in the SFWMD Permit Manual (SFWMD, 1987).

The surface water management system for the project facilities located within the developed area will be designed such that the peak post-development discharges from the ICL site will not exceed the peak pre-development discharges into the existing onsite drainage ditch. Detention basins and discharge control structures will ensure that post-development peak discharges will not exceed the pre-development peak discharge. By virtue of the existing topography, the stormwater runoff from the undeveloped areas outside the developed area will continue to follow the existing course.

The following design criteria are specified in the SFWMD Permit Manual:

a. Design Storms

- 100-year, 72-hour storm for emergency spillway elevations of detention basins and building elevations.
- 25-year, 72-hour storm for principal spillway elevations of detention basins, permanent swales and ditches, and culverts.
- 10-year, 72-hour storm for road crown elevations and temporary diversion ditches.

b. Rainfall Frequencies for the Site Area

- 100-year, 24-hour: 9.0 inches
  72-hour: 12.2 inches

- 25-year, 24-hour: 7.0 inches
  72-hour: 9.5 inches

- 10-year, 24-hour: 5.8 inches
  72-hour: 7.9 inches

- 3-year, 24-hour: 4.3 inches

- Rainfall Distribution: SCS-Type III

c. Basin Outlet Structures

- V-notch bleeder (control structure) is to pass the first inch of runoff.

- Combined discharge capacity of principal and emergency spillways to accommodate peak runoff from 100-year, 72-hour storm.

3.8.3.2 <u>Runoff Analysis</u>

<u>Power Block and Coal Handling Areas</u>

SCS Technical Release No. 55, (TR55), (USDA, 1986) was used to determine pre-developed as well as post-developed peak runoff discharges for the site. Weighted runoff coefficients were determined by percentage of impervious area due to development and soil type. Based on the soil types found in the site area, a site-wide SCS classification of soil Type C was established (USDA, 1986). In conjunction with a particular storm event, runoff values were determined. Based on these values, stormwater detention basins, ditches, swales, and culverts were sized to prevent excess discharges and thus maintain the pre-developed flow rate of the existing drainage ditch.

The basin sizes in the analysis using TR-55 were determined for the maximum 24-hour storm, but additional volume has been provided to include the incremental runoff volume due to the 48-hour precipitation prior to the peak flow in the 72-hour storm, as defined by the SFWMD Permit Information Manual (SFWMD, 1987) and shown on Figure 3.8.3-1. The design criteria for basin sizing as addressed in Section 3.8.3.1 include the incremental volume storage up to the 25-year storm during principal spillway operation, and the 100-year storm during emergency spillway operation. The stormwater basins outlets have been sized to pass the peak flow from the 100-year, 24-hour storm.

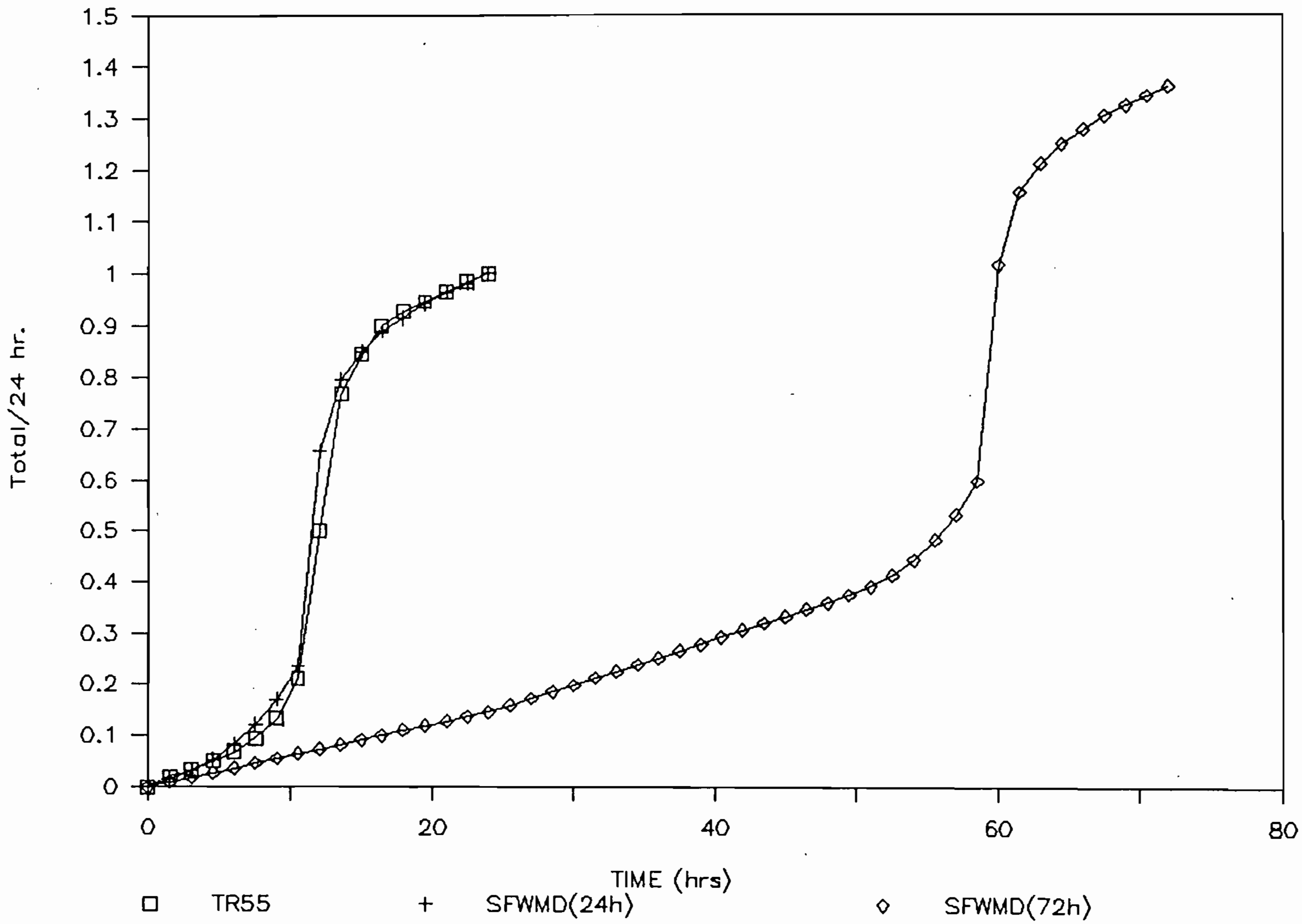
Drainage ditches receiving water from detention basins are sized using the peak discharge from their respective basin. For swales and ditches receiving only overland flow, an average peak runoff per acre was established using SCS Technical Release No. 55 and a 25-year and 24-hour storm event. For runoff curve numbers (CN) spanning the possible range of CN from 89 to 93, a discharge of 4 cfs per acre was established.

Inactive Coal Storage Area

The inactive coal storage area basin was sized using a 100-year, 24-hour rainfall and a runoff coefficient of 0.73 (EPA, 1979). Additionally, direct rainfall on the pond itself was added to the volume required. Surface water runoff from the inactive coal pile area will be collected in a lined detention basin. The runoff will be pumped to a wastewater treatment facility for processing for possible use as process and cooling water needs.

Figure 3.8.3-1.
COMPARISON OF SFWMD AND TR-55 RAINFALL DISTRIBUTIONS

Source: SFWMD and TR-55



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Wetland Runoff

Seven naturally occurring wetlands within the property boundary (23.4 acres) will be preserved. An additional 1 acre of wetland in the form of a man-made ditch, as shown on Figure 3.1.1-1 (Site Plan), will be rerouted and then maintained on the project site. A 50-foot buffer of pine flatwoods surrounding the three wetlands in the central portion of the property and a wetland on the northwest corner of the property will also be maintained. The other three wetlands are surrounded by preserved uplands and will not be disturbed. The impact of facility access road and railroad spurs will be minimized by incorporating the wetland areas into the project's surface water management plan such that excessive and unseasonal flooding or drying will be avoided.

For the wetland adjacent to the cooling water storage pond, a 3-year, 24-hour storm event (assumed to be equivalent to the mean annual) was used in pre- and post-development runoff assessments. The analysis was performed to determine the deficient mean annual peak discharge required to feed the wetland from a detention basin (see Section 3.8.5.2). This discharge to the wetland will be through a rip-rapped channel or grassed swale.

3.8.4 CONSTRUCTION DRAINAGE

Rerouting of a portion of the existing onsite drainage ditch and construction of the surface water runoff collection basins will be performed early in the project schedule. This will facilitate site drainage and the use of these basins as sedimentation basins during clearing, rough grading, excavation, and construction. A rough grading plan is shown in Figure 3.8.4-1.

The construction activities will result in disturbance of land in the following areas:

- Power block and switchyard area
- Construction laydown area
- Coal handling and storage areas, including the rail car unloading facility
- Plant roads and railroad
- Trenches for the circulating water piping system and other underground utilities
- Cooling water storage pond
- Runoff collection basins
- Drainage ditches, diversion ditches, and the wetland water distribution channel
- Rerouted portion of the existing north-south drainage ditch traversing the site

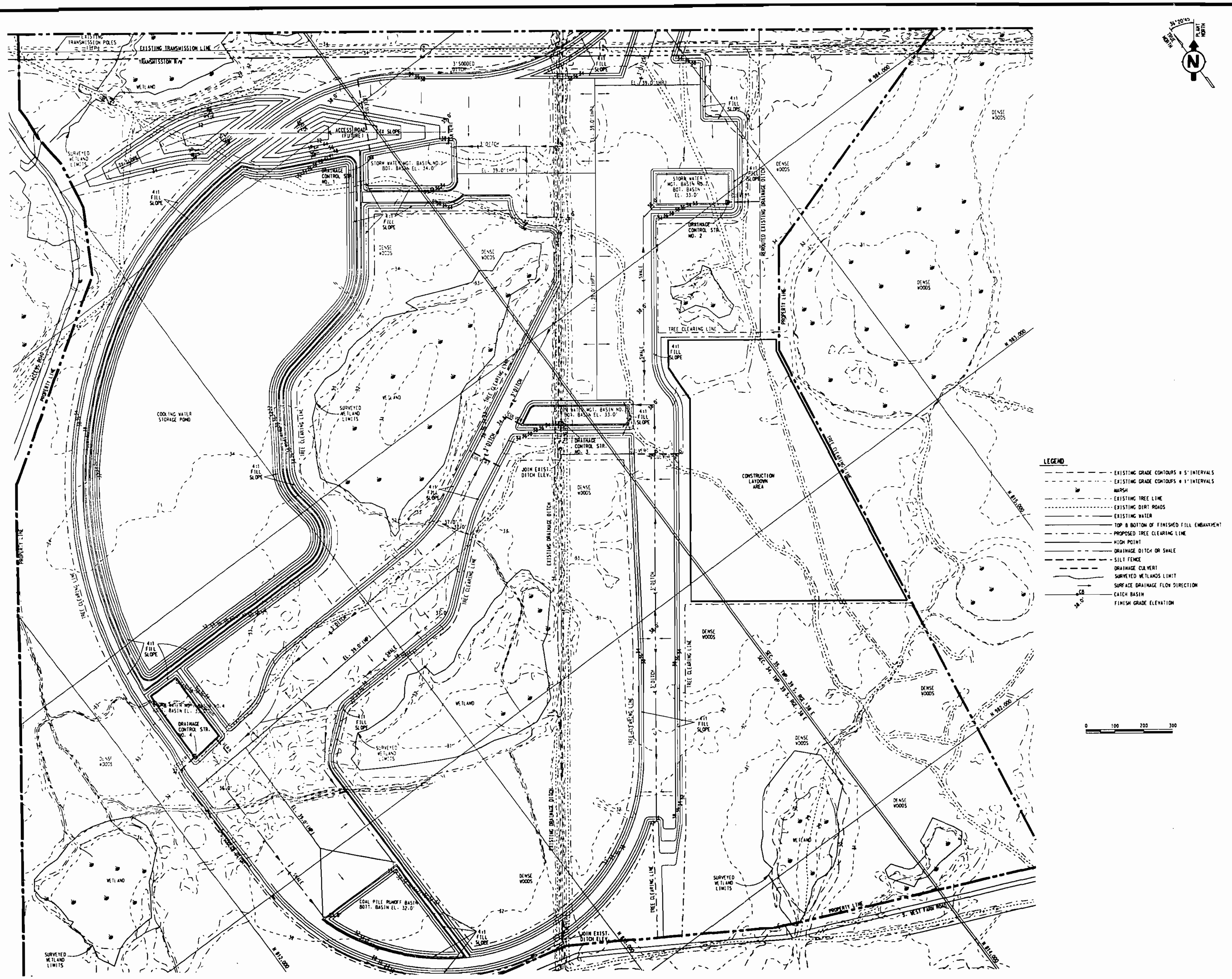

Figure 3.8.4-1.

ROUGH GRADING PLAN

Source: Bechtel, 1990

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- Additional temporary construction buildings including offices, warehouses, and shops

To collect the runoff water from these areas, a total of five collection basins will be built as shown on Figure 3.8.2-1. During construction, these basins will be used as sedimentation basins. The runoff water from these basins will be discharged to the existing drainage ditch, either directly or via perimeter ditches to the north and southwest of the plant area outside the railroad loop.

Natural characteristics affecting erosion and sediment transport include rainfall intensity, type of soil, topography, and vegetation cover. At the ICL site, several of these influences offset each other. Although rainfall intensity is high, the topography is relatively level, which will minimize the water flow velocity and sediment transport capacity. The flat slope of the land will tend to limit the amount of material that could be transported by runoff. Erosion control measures will include provision of diversion ditches, silt fences, straw bale dikes, and sediment traps. Hydroseeding and mulching will be used on all rough graded areas to establish a ground cover on slopes, drainage ditches, and swales.

The collection basins that will be provided early in construction will be used to allow considerable time for suspended solids to settle prior to discharge. They will remain in operation during construction and will be cleaned periodically to maintain their function. The mitigation measures used for the erosion and sedimentation control during construction are discussed below. The exact location, size, and number of these control features have been established for the construction planning phase. Considerations have been given to construction sequence, construction season, local topography, and final drainage scheme in establishing erosion and runoff control details. Additional measures, as required during construction, will be implemented by the construction superintendent.

3.8.4.1 Erosion and Sediment Control Measures

Sediment and erosion control measures will be strictly applied to limit the generation and transport of soil by runoff. The details of the erosion and sedimentation control plan for the project have been developed. The control measures noted below in the text and illustrated on attached figures have been used in developing these details. All management, vegetative, and structural erosion and sedimentation control practices have been designed, and will be constructed and maintained according to the requirements of the SFWMD.

Management Practices

The following management practices will be adhered to for erosion and sedimentation controls:

- A schedule of installation will be developed to minimize the disturbed area at any time.
- Construction traffic shall be limited to access easement roads and areas to be graded. Traffic will be prohibited from entering the drainage ditches and wetlands.
- Protective measures (e.g., silt fences) will be implemented to prevent transport of sediment into any wetland area or drainage course.
- The construction superintendent shall have overall responsibility for plan implementation. He shall also be responsible for ensuring that construction workers and subcontractors are aware of the provisions of the plan.

Vegetative Practices

The following vegetative practices for erosion and sedimentation control will be incorporated during construction:

Temporary Seeding

The detention basin embankments, perimeter dikes, topsoil stockpiles, and areas to be rough graded during the initial phase of construction shall be seeded or sodded as per SFWMD requirements.

Jute Mesh

Jute mesh or other degradable channel lining material shall be used to aid in establishing grass growth. It may also be applied on road and track side ditches, if required.

Structural Practices

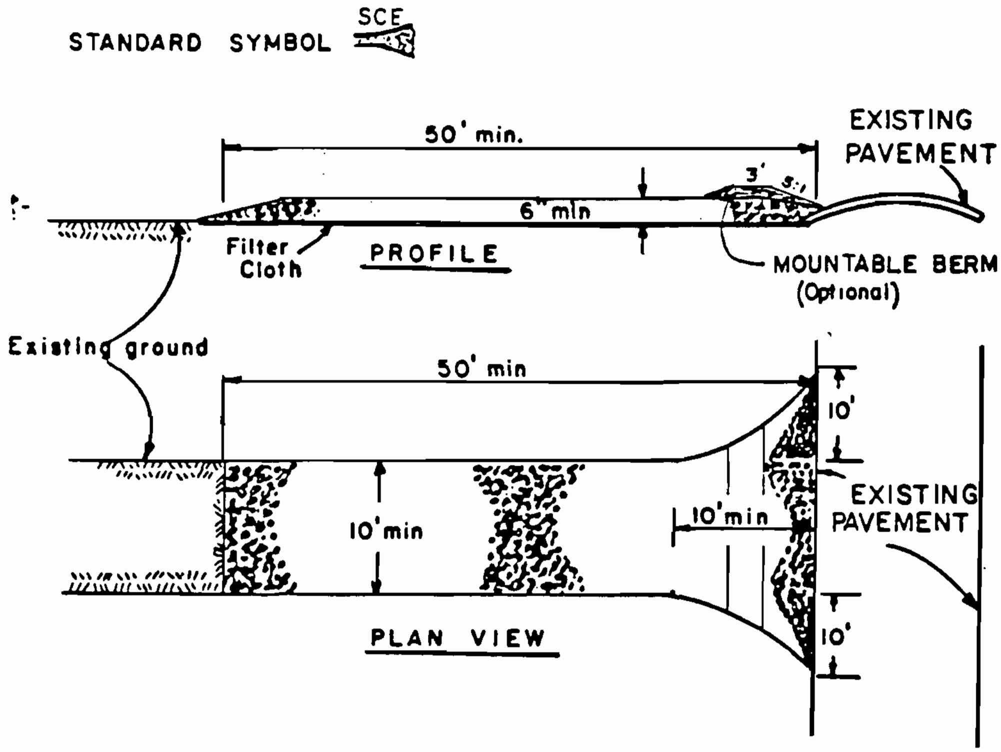
The structural practices to control and intercept sediment from runoff and to retain coarse sediment particles from reaching surrounding water bodies, will include provision of perimeter dikes, riprap outlet structures, straw bale dikes or barriers, silt fences, diversion dikes, graveled construction entrances, and detention basins.

3.8.4.2 Description of the Control Facilities

Temporary Construction Entrance

Construction laydown and storage areas will be accessed via roads that will become permanent plant roads. Roads in the construction area will be upgraded with gravel to facilitate heavy truck traffic as needed. Typical details of the temporary construction entrance from the main road are shown on Figure 3.8.4-2.

STABILIZED CONSTRUCTION ENTRANCE
not to scale



CONSTRUCTION SPECIFICATIONS

1. Stone Size - Use 2" stone, or reclaimed or recycled concrete equivalent.
2. Length - As required, but not less than 50 feet (except on a single residence lot where a 30 foot minimum length would apply).
3. Thickness - Not less than six (6) inches.
4. Width - Ten (10) foot minimum, but not less than the full width at points where ingress or egress occurs.
5. Filter Cloth - Will be placed over the entire area prior to placing of stone. Filter will not be required on a single family residence lot.
6. Surface Water - All surface water flowing or diverted toward construction entrances shall be piped across the entrance. If piping is impractical, a mountable berm with 5:1 slopes will be permitted.
7. Maintenance - The entrance shall be maintained in a condition which will prevent tracking or flowing of sediment onto public rights-of-way. This may require periodic top dressing with additional stone as conditions demand and repair and/or cleanout of any measures used to trap sediment. All sediment spilled, dropped, washed or tracked onto public rights-of-way must be removed immediately.
8. Washing - Wheels shall be cleaned to remove sediment prior to entrance onto public rights-of-way. When washing is required, it shall be done on an area stabilized with stone and which drains into an approved sediment trapping device.
9. Periodic inspection and needed maintenance shall be provided after each rain.

Figure 3.8.4-2
TYPICAL DETAILS OF
STABILIZED CONSTRUCTION ENTRANCE

Source: USDAG, SCS

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Sedimentation (Detention) Basins

Sedimentation (detention) basins will be developed as required by excavation to intercept the runoff from the construction area and to prevent coarse sediment particles from reaching the surrounding water bodies. The basin will have an outlet that permits draining at a slow rate during a storm, according to SFWMD requirements and as shown in Figure 3.8.4-3. These basins will remain in operation during construction, and will be mucked out periodically to maintain their function. Upon completion of construction, the basins will be cleaned and will be incorporated into the stormwater management plan. Typical features of the sedimentation basin are shown in Figure 3.8.4-4.

Swales and Ditches

Swales will be formed to direct the runoff to sedimentation basins. These swales will be excavated, graded, and stabilized with rock or by sodding or seeding. The cross section of the swales will be V-shaped or trapezoidal and designed to carry runoff from contributing area with a velocity of 2.0 fps or the allowed non-erosive velocity for the swale material. Typical details of the swales are shown in Figure 3.8.4-5.

Straw Bale Dikes and Silt Fences

Straw bale dikes will be constructed by placing the bale perpendicular to the flow. They will be keyed in and stacked as shown in Figure 3.8.4-6. Silt fences (Figure 3.8.4-7) will also be used to control the release of sediment laden runoff from the site.

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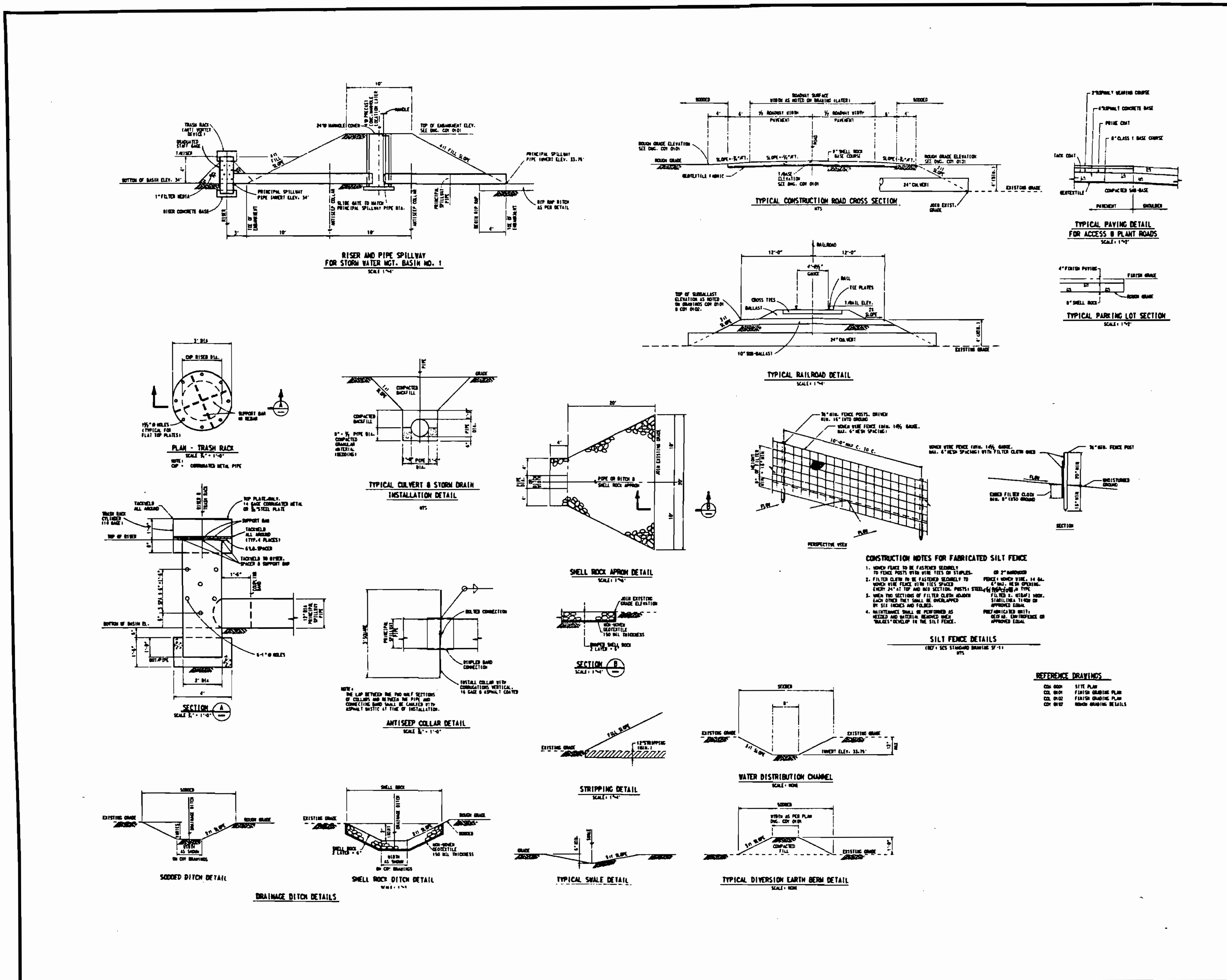

Figure 3.8.4–3
EROSION AND SEDIMENTATION CONTROL – TYPICAL DETAILS (SHEET 1)

Source: Bechtel, 1990

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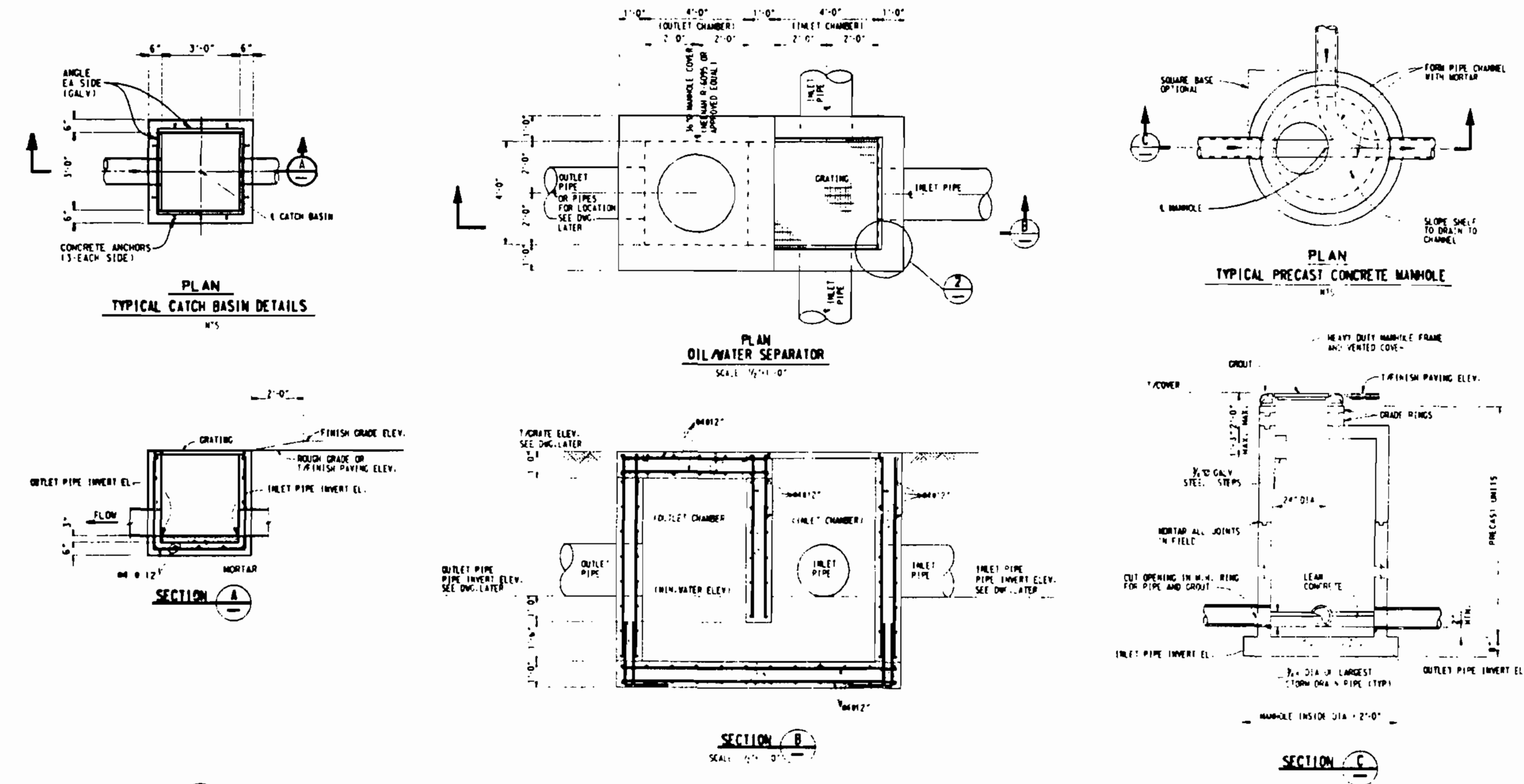
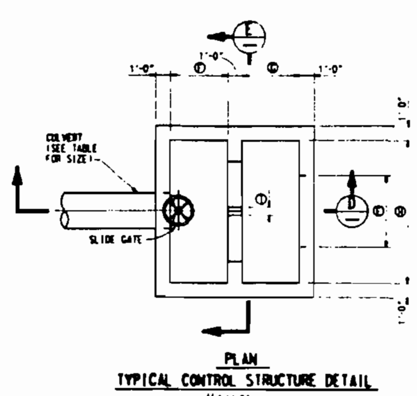
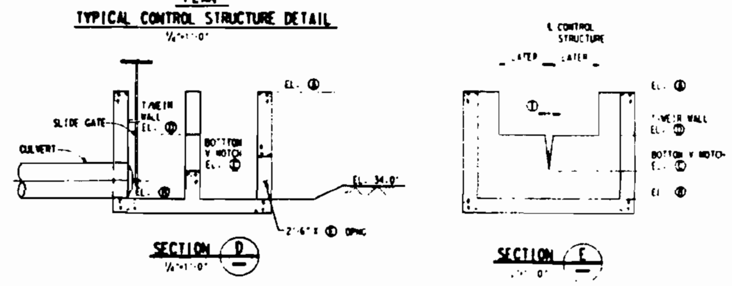
Figure 3.8.4–4
EROSION AND SEDIMENTATION CONTROL – TYPICAL DETAILS (SHEET 2)





DRAINAGE CONTROL STRUCTURES					
DETAIL	UNITS	BASIN 1	BASIN 1	BASIN 1	BASIN 1
A	FT	38.0	38.0	38.0	38.0
B	FT	34.0	34.0	34.0	33.0
C	FT	35.0	35.0	35.0	34.0
D	FT	35.5	35.5	35.5	34.5
E	FT	7	4	4	7
F	FT	4	3	3	4
G	FT	4	3	3	4
H	FT	7	4	4	7
I	FT	2	2	2	2
CULVERT	IN	30	24	24	30



Source: Bechtel, 1990

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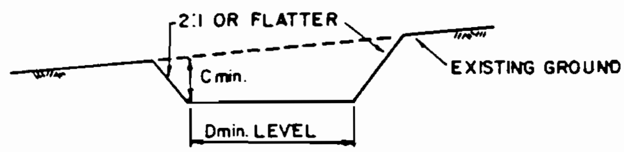
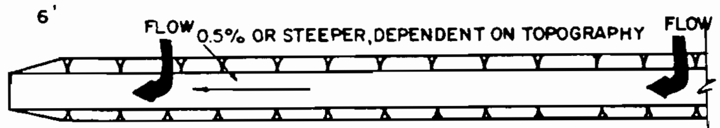
TEMPORARY SWALE



CROSS SECTION

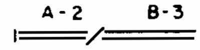
	SWALE A	SWALE B
C	1'	1'
D	4'	6'

OUTLET AS REQUIRED
SEE ITEM 8 BELOW



PLAN VIEW

STANDARD SYMBOL
A - 2 B - 3



CONSTRUCTION SPECIFICATIONS

1. ALL TEMPORARY SWALES SHALL HAVE UNINTERRUPTED POSITIVE GRADE TO AN OUTLET.
2. DIVERTED RUNOFF FROM A DISTURBED AREA SHALL BE CONVEYED TO A SEDIMENT TRAPPING DEVICE.
3. DIVERTED RUNOFF FROM AN UNDISTURBED AREA SHALL OUTLET DIRECTLY INTO AN UNDISTURBED STABILIZED AREA AT NON-EROSIVE VELOCITY.
4. ALL TREES, BRUSH, STUMPS, OBSTRUCTIONS, AND OTHER OBJECTIONABLE MATERIAL SHALL BE REMOVED AND DISPOSED OF SO AS NOT TO INTERFERE WITH THE PROPER FUNCTIONING OF THE SWALE.
5. THE SWALE SHALL BE EXCAVATED OR SHAPED TO LINE, GRADE, AND CROSS SECTION AS REQUIRED TO MEET THE CRITERIA SPECIFIED HEREIN AND BE FREE OF BANK PROJECTIONS OR OTHER IRREGULARITIES WHICH WILL IMPEDE NORMAL FLOW.
6. FILLS SHALL BE COMPACTED BY EARTH MOVING EQUIPMENT.
7. ALL EARTH REMOVED AND NOT NEEDED ON CONSTRUCTION SHALL BE PLACED SO THAT IT WILL NOT INTERFERE WITH THE FUNCTIONING OF THE SWALE.
8. STABILIZATION SHALL BE AS PER THE CHART BELOW:

FLOW CHANNEL STABILIZATION

TYPE OF TREATMENT	CHANNEL GRADE	A (5 AC OR LESS)	B (5 AC - 10 AC)
1	0.5-3.0%	SEED AND STRAW MULCH	SEED AND STRAW MULCH
2	3.1-5.0%	SEED AND STRAW MULCH	SEED USING JUTE OR EXCELSIOR
3	5.1-8.0%	SEED WITH JUTE OR EXCELSIOR; SOD	LINED RIP-RAP 4-8" RECYCLED CONCRETE EQUIVALENT
4	8.1-20%	LINED 4-8" RIP-RAP	ENGINEERED DESIGN

9. PERIODIC INSPECTION AND REQUIRED MAINTENANCE MUST BE PROVIDED AFTER EACH RAIN EVENT.

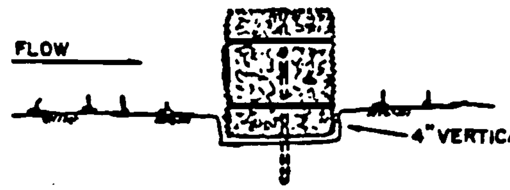
Figure 3.8.4–5
TYPICAL DETAILS OF TEMPORARY SWALE

Source: USDAG, SCS

INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

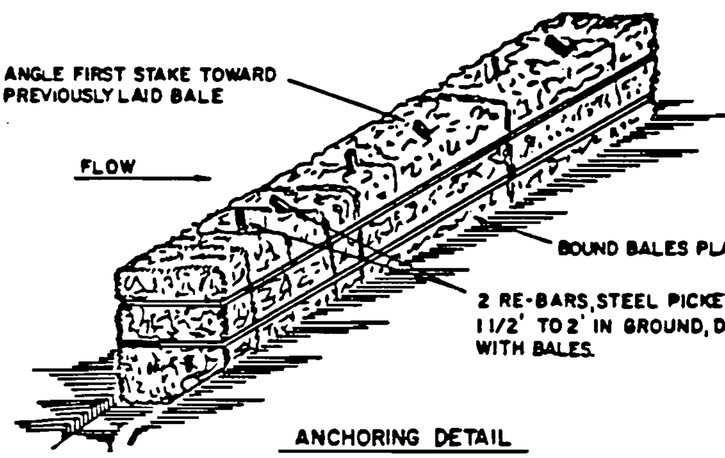
STRAW BALE DIKE



BEDDING DETAIL

STANDARD SYMBOL

SBD



ANCHORING DETAIL

CONSTRUCTION SPECIFICATIONS

1. BALES SHALL BE PLACED AT THE TOE OF A SLOPE OR ON THE CONTOUR AND IN A ROW WITH ENDS TIGHTLY ABUTTING THE ADJACENT BALES.
2. EACH BALE SHALL BE EMBEDDED IN THE SOIL A MINIMUM OF (4) INCHES, AND PLACED SO THE BINDINGS ARE HORIZONTAL.
3. BALES SHALL BE SECURELY ANCHORED IN PLACE BY EITHER TWO STAKES OR RE-BARS DRIVEN THROUGH THE BALE. THE FIRST STAKE IN EACH BALE SHALL BE DRIVEN TOWARD THE PREVIOUSLY LAID BALE AT AN ANGLE TO FORCE THE BALES TOGETHER. STAKES SHALL BE DRIVEN FLUSH WITH THE BALE.
4. INSPECTION SHALL BE FREQUENT AND REPAIR REPLACEMENT SHALL BE MADE PROMPTLY AS NEEDED.
5. BALES SHALL BE REMOVED WHEN THEY HAVE SERVED THEIR USEFULNESS SO AS NOT TO BLOCK OR IMPEDE STORM FLOW OR DRAINAGE.

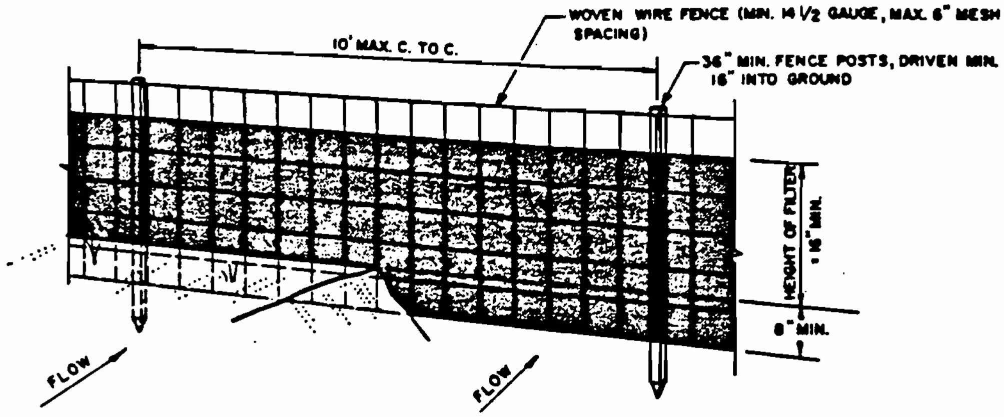
Figure 3.8.4–6
TYPICAL DETAILS OF STRAW BALE DIKE

Source: USDAG, SCS

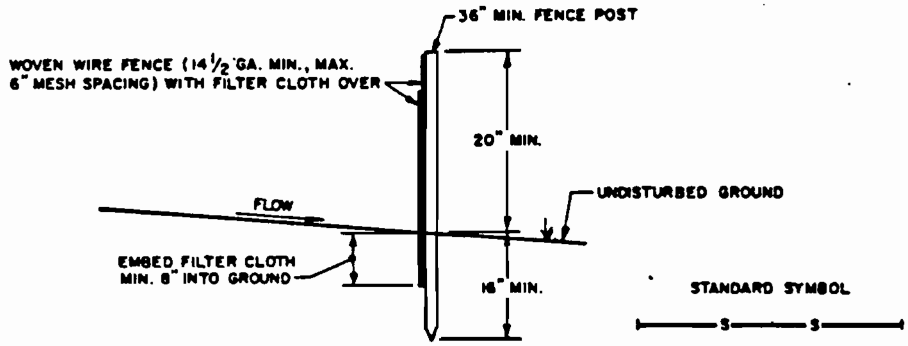
INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

SILT FENCE



PERSPECTIVE VIEW



SECTION

CONSTRUCTION NOTES FOR FABRICATED SILT FENCE

1. WOVEN WIRE FENCE TO BE FASTENED SECURELY TO FENCE POSTS WITH WIRE TIES OR STAPLES.
2. FILTER CLOTH TO BE FASTENED SECURELY TO WOVEN WIRE FENCE WITH TIES SPACED EVERY 24" AT TOP AND MID SECTION.
3. WHEN TWO SECTIONS OF FILTER CLOTH ADJOIN EACH OTHER THEY SHALL BE OVER-LAPPED BY SIX INCHES AND FOLDED.
4. MAINTENANCE SHALL BE PERFORMED AS NEEDED AND MATERIAL REMOVED WHEN "BULGES" DEVELOP IN THE SILT FENCE.

POSTS: STEEL EITHER T OR U TYPE OR 2" HARDWOOD

FENCE: WOVEN WIRE, 14 GA. 6" MAX. MESH OPENING

FILTER CLOTH: FILTER X, MIRAFI 100X, STABILINKA T140N OR APPROVED EQUAL

PREFABRICATED UNIT: GEOFAB, ENVIROFENCE, OR APPROVED EQUAL.

Figure 3.8.4–7
TYPICAL DETAILS OF SILT FENCE

Source: USDAG, SCS

INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

<u>Dewatering During Construction</u>

During construction, dewatering will probably be required inside the work area. Water will be pumped out of the excavation and diverted through a straw bale filter dike or silt fence or sedimentation basins prior to release.

3.8.4.3 <u>Construction Monitoring and Maintenance</u>

In general, all erosion and sedimentation control measures will be checked weekly and after each significant rainfall. The following items will be checked in particular:

- Sedimentation basins will be cleaned out when the level of sediment buildup reaches approximately 1 foot.

- Gravel or riprap outlets will be checked regularly for sediment buildup. If the gravel is clogged with silt, it will be removed and cleaned or replaced.

- Straw bale barriers or dikes will be checked regularly for undermining or deterioration of the bales.

- Seeded and sodded areas will be checked regularly. Areas will be fertilized and reseeded as needed.

- Silt fences and filter barriers shall be inspected after each rainfall and during prolonged rainfall. Required repairs will be made immediately.

- Should the fabric on a silt fence or filter barrier decompose or become ineffective prior to the end of the expected usable life and the barrier still be necessary, the fabric will be replaced promptly.

- Sediment deposits at barriers will be removed after heavy storm events. They will be removed when deposits reach approximately one-half the height of the barrier.

- Sediment deposits remaining in place after the silt fence or silt barrier is no longer required will be dressed to conform with the existing grade, prepared, and seeded.

3.8.4.4 Permanent Stabilization

Areas disturbed by construction will be stabilized with permanent seeding immediately following finish grading. Finish grading will include regrading and seeding of the areas used by the construction facilities and perimeter dike system and return the areas to natural drainage. Vegetated areas will be re-established and stabilized with appropriate seed mixture. Discharge from the site during and after construction will be directed to the detention/stormwater management basins 1 through 5.

3.8.5 PERMANENT SITE DRAINAGE

3.8.5.1 Introduction

The permanent drainage facilities will consist primarily of a series of open ditches and swales, catchbasins, oil/water separators, storm drainage piping, culverts, stormwater detention basins, and a wetland water distribution channel (Figure 3.8.2-1). The stormwater runoff from the developed area will be directed to the detention basins which will have bleeder type devices to control the discharge rate in compliance with the SFWMD surface water discharge requirements. Discharge will be accomplished using a bleeder type v-notch weir contained in a two chambered structure as shown in Figure 3.8.4-3, and as recommended by the SFWMD. The basins, installed early during construction to provide sediment and erosion control, will be cleaned upon construction completion and maintained thereafter to control site drainage or stormwater runoff.

Stormwater runoff from the newly added non-porous surfaces (i.e., paved roads, parking lots, roofs, yard area, etc.) will be collected and conveyed to the detention basins utilizing a system of curbing, catch basins, and underground piping. The system will also include design features (e.g., oil/water separators) as necessary, to treat and/or remove any potential contaminants, and to maintain acceptable water quality conditions. The detention basin outlet structure will be provided with a manual control valve, or sluice gate, to prevent discharge from the basins during contamination spills and, when needed, to control the release.

The site drainage system will convey the onsite runoff to the existing drainage ditch, with some rerouting of its existing alignment. With the exception of the runoff basin for the inactive coal storage area, all of the stormwater runoff from the detention basins will eventually be discharged into the existing drainage ditch traversing the central portion of the site. The stormwater runoff from the inactive coal storage area will be detained and treated, and recycled for plant cooling and process water use.

The following sections address the management of the stormwater runoff from the proposed developed areas located within the railroad loop. The site has been broken down into the following general areas for analysis:

- Power block area
- Coal handling area
- Inactive coal storage area

3.8.5.2 Proposed Power Block Area Drainage System

The total power block area is approximately 21 acres. This area will be elevated to a finished grade of approximately 39 feet NGVD. Stormwater runoff from the area will be directed to three permanent collection basins (Nos. 1, 2, and 3). Basins 1 and 2 lie to the west and east of the power block area, respectively. Basin 3 is located to the south of the power block area. These basins are shown on Figure 3.8.2-1.

The stormwater runoff from curbed areas (potentially contaminated areas) will be channelled to catch basins and oil/water separators before discharge to the basin. The following table lists some key figures for detention basins 1 through 3:

				Basin Size		Max
	Drainage	Peak Discharges		Surface	Volume	W.E.
	Area	Pre	Post	Area	Req'd	NGVD
Basin	(ac)	(cfs)	(cfs)	(ac)	(ac-ft)	(ft)
1	10.7	32	75	1.18	3.0	37
2	4.5	13	33	.80	1.5	36
3	5.6	17	44	.94	2.0	36

The depth of the basins below finish grade will be 5 feet. This includes a maximum water depth of 3 feet during emergency spillway operation and a minimum freeboard of 2 feet. The bottom of the basins will be above the existing groundwater level of the area. A total of 6.5 acre-feet of detention volume will be provided by these three basins in the power block area for stormwater management purposes.

Discharge from basins 2 and 3 will be directed to a rip-rapped apron and then conveyed to the existing drainage ditch. A perimeter ditch will convey the basin 1 discharge to the existing drainage ditch, as shown on Figure 3.8.2-1. A portion of the runoff from basin 1 will be diverted and distributed to the wetland immediately south of the basin.

The area draining to the wetland adjacent and east of the cooling water storage pond has a pre-developed drainage area of 21 acres. Due to the construction of the cooling water storage pond and plant layout, the contributing area is reduced to 11.5 acres. The existing pre- and post-peak discharges for the mean annual (3-year, 24-hour storm event as provided by the SFWMD, 1987) storm, are 20 and 13 cfs, respectively, as determined by SCS Technical Release No. 55 (USDA, 1986). As a result of this decreased contributing area, this wetland has a peak flow deficiency of 7 cfs for the 3-year 24-hour storm event. This deficiency will be compensated by providing runoff from basin 1 through a perforated vertical riser pipe surrounded by a rip-rap filter. The discharge will be distributed to the wetland by a rip-rapped discharge channel as shown on Figure 3.8.2-1.

3.8.5.3 Proposed Coal Handling Area Drainage System

The coal handling area for the unit is comprised of approximately 9 acres. The area will be elevated to a finished grade of approximately 38 feet NGVD at the center, sloping outward to swales, and eventually discharged to the retention/detention basin 4. The following table lists some key features for detention basin 4:

Basin	Drainage Area (ac)	Peak Discharges Pre (cfs)	Peak Discharges Post (cfs)	Basin Size Surface Area (ac)	Basin Size Volume Req'd (ac-ft)	Max W.E. NGVD (ft)
4	9.1	27	60	1.11	2.5	36

Basin 4 will detain a volume of 2.5 acre-feet for stormwater management purposes. The discharge from basin 4 will be from the same type outlet structure as mentioned in Section 3.8.5.2 to a rip-rapped apron and then via a perimeter ditch to the existing drainage ditch.

3.8.5.4 Proposed Inactive Coal Storage Area Drainage System

The inactive coal storage drainage area (Figure 3.8.2-1) for the plant is approximately 6 acres. This area will be elevated to a finished grade of approximately 37 feet NGVD at the center and slope outward to a collection basin. The collection basin will provide a detention volume of 3.6 acre-feet, as calculated according to methodology described in Section 3.8.3.2, for the stormwater runoff from the inactive coal storage area. This basin will be located adjacent to the inactive coal storage area and have an approximate surface area of 1.6 acres. The maximum water depth will be 3 feet with an additional 2 feet of freeboard provided. The basin will be 5 feet in depth below the final grading elevation.

During the construction phase, this collection basin will function as a sediment and erosion control basin and will thus require the same type of discharge structure as mentioned in Section 3.8.4.2. Upon completion of construction, this structure must be sealed to prevent discharge to the drainage ditch. Additionally, prior to the operation of the plant, the detention basin and the drainage swale in the coal storage area will be lined with a synthetic impervious liner to eliminate seepage of runoff.

The stormwater runoff from the inactive coal storage is considered to be wastewater. Runoff collected from this area is treated to adjust pH and detained in the basin. Treated runoff is transfered to the cooling tower sidestream softener for cooling tower use.

3.8.5.5 Proposed Cooling Water Storage Pond Area

The cooling water storage pond will be sized to store water pumped from Taylor Creek/Nubbin Slough. The pond will be lined and the water will be used for plant cooling and process water make-up. The details of the cooling water pond are discussed in Section 3.5.1.2.

3.9 MATERIALS HANDLING

3.9.1 CONSTRUCTION MATERIALS HANDLING

Major components for the cogeneration plant include:

- Main steam turbine
- Turbine generator
- Pulverized coal-fired boiler
- Spray dryer absorber system
- Baghouse
- Cooling tower
- Transformers

The components are expected to be delivered by rail or truck. No offsite or onsite upgrading of road or rail facilities is expected, other than the new road and rail facilities required for normal operations. Once onsite, materials will be unloaded and transported by using portable cranes and trucks. Some of the heaviest items will require rail delivery and special rigging for onsite handling.

The proposed location for construction operations which include laydown areas, construction warehouses, fabrication shops, and equipment maintenance is shown in Figure 3.8.4-1, entitled "Rough Grading Plan."

Fugitive dust, surface water runoff, and waste disposal associated with material handling in these areas will be controlled as follows:

- Dust suppression will be accomplished by watering the roads, parking lots, and laydown areas, as needed.

- Runoff detention ponds will be used to settle suspended sediment from rainfall runoff.

- Related trash and other nonhazardous organic debris will be collected for offsite disposal by a licensed contractor.

- Commercial salvage of metal wastes will be considered. If salvage is not feasible, these wastes will be removed from the site by a licensed contractor.

3.9.2 OPERATIONS MATERIALS HANDLING

The handling and storage of fuels (natural gas, No. 2 oil, and coal) are discussed in Section 3.3. Handling and storage of flue gas desulfurization byproducts, wastewater treatment sludges, and other low volume waste streams are discussed in Section 3.7.

Other operations materials include lime, ammonia, water and wastewater treatment chemicals, lubrication oils, and turbine generator coolant and purge gases.

Water and wastewater treatment chemicals (e.g., acid, caustic, sodium hypochlorite, carbohydrazide) will be stored in or near the water treatment building.

Hydrogen and nitrogen gases will be stored in bottles on trailers or in sheds adjacent to the gas distribution system which serves the cogeneration plant.

Lime will be delivered to the site by self-unloading pneumatic railcars or self-unloading trucks. The lime will be pneumatically conveyed to the lime silo which will be equipped with a bin-vent type filter to minimize fugitive dust emissions. The silo will have a total capacity of 1500 tons, representing a 5-day storage capacity when continuously firing the design fuel at full load. The lime silo will be serviced by a dedicated track siding sized to allow lime delivery twice a week by train consisting of 14 pneumatic self-unloading railcars.

The SNCR reagent will be stored onsite in an appropriate storage facility located within appropriately sized containment walls.

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4.0 EFFECTS OF SITE PREPARATION AND PROJECT AND ASSOCIATED FACILITIES CONSTRUCTION

4.1 LAND IMPACT

4.1.1 GENERAL CONSTRUCTION IMPACTS

The Indiantown Cogeneration, L.P., project includes 232 acres within the property boundary of the site. A permanent easement of approximately 75 acres across the adjacent Florida Steel Corporation property will be used for a new rail spur. This easement will be between the Caulkins Citrus Plant and the abandoned Florida Steel Company properties. The only other land affected by the proposed ICL facility will be in the corridor for the cooling water pipeline routed along the CSX right-of-way (see Section 6.2).

In accordance with the Martin County Planned Unit Development (Industrial) Agreement (PUD(i)), 25 percent of the pine flatwoods, or 50.5 acres, of the land subject to the Agreement will be set aside as upland preserve and will not be disturbed. Designated upland preserve areas will be subject to an upland preserve and restoration management plan designed to remove exotic vegetation, revegetate in partially disturbed areas, and protect existing vegetation by using staking and barricading procedures during construction. The upland preserve areas that have been identified for the project are along the southern portion of the site on the exterior of the rail loop as shown on Figure 4.1.1-1.

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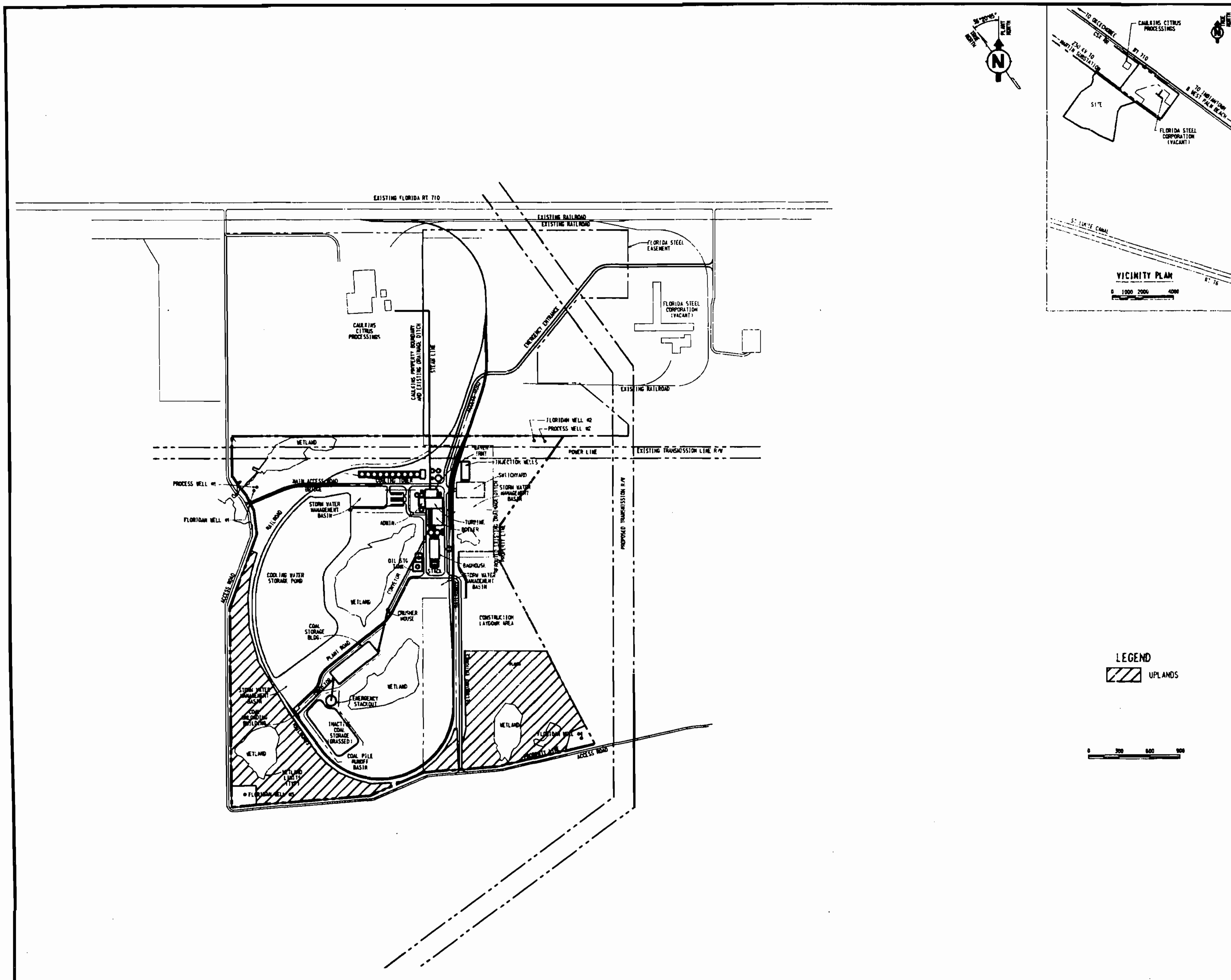

Figure 4.1.1-1.

UPLAND PRESERVES

Source: Bechtel, 1990

INDIANTOWN
COGENERATION
PROJECT

Indiantown Cogeneration, L.P.

4.1.1.1 <u>ICL Project Site</u>

The following construction activities are associated with overall development of the project site:

- Runoff storage basins and drainage ditches will be constructed and used as sedimentation basins to collect runoff during grading, excavation, and construction.

- The operational site drainage system (inclusive of drainage swales, ditches, and runoff collection basins) will be developed.

- Earthwork will be performed (i.e., removal of topsoil as necessary for constructing foundations for plant facilities, construction of access roadways, grading to subgrades, excavating for placement of piping and conduit).

- In areas where it will be necessary, dewatering will occur using wells, well points, and sumps (see Section 4.3.1).

- The existing Caulkins entrance road from SR 710 will be extended to provide access to the ICL facility. Other onsite permanent roads as well as temporary construction roads, will be constructed.

- A new rail siding will be developed from the CSX railroad to the onsite rail loop across an easement on Florida Steel Corporation property. This development will include construction of the rail bed foundation which is composed of properly compacted sub-ballast (fill material) covered by crushed rock ballast. Suitable drainage openings in this foundation will be provided to maintain existing drainage patterns.

- Temporary (construction power) and permanent underground electrical and utility piping systems will be installed.

- Temporary laydown and construction parking areas will be constructed by grading and adding gravel to certain areas. Once construction is completed, the area will be stabilized.

- The land disturbed by construction will be approximately 118.6 acres. Once construction is completed 106.6 acres will remain permanently disturbed due to buildings and operations.

4.1.1.2 Power Block Area

Construction of the proposed ICL power block area will require clearing, grubbing, and grading in order to raise the area approximately 4 feet to El. 39 ft NGVD. Where possible, fill will be obtained onsite; when brought in, it will be obtained from non-wetlands areas. The raising of this area minimizes the amount of dewatering that would be required due to the relatively high groundwater table. An existing drainage ditch traverses the site and will be relocated to the east of the power block; its final destination will remain unaltered.

No explosives are planned for use during construction in this area.

4.1.1.3 Coal Storage and Handling Areas

The area where the inactive coal pile and emergency coal pile are to be located will be cleared, grubbed, graded, and a liner installed to prevent any potential pollutants from entering the groundwater. A runoff pond will also be constructed with a liner to intercept any water draining from these two coal piles. A physical barrier (described in Section 3.3.4) will be constructed beneath the active coal pile to prevent groundwater contamination.

The excavation of the coal car unloading hopper (approximately 40 feet deep) will encounter groundwater. A cofferdam of similar construction technique will be constructed around the perimeter of the unloading hopper to minimize the influent of groundwater and thereby minimizing any impact on the groundwater table and wetlands.

4.1.1.4 <u>Construction Wastes</u>

Waste materials will be disposed of in accordance with applicable rules and regulations. Construction wastes, such as scrap wood and metal, will be transferred to a specified storage area onsite where they will be separated and stockpiled for salvage. General waste materials (i.e., garbage) will be collected in appropriate waste collection containers for disposal at an approved offsite location.

Waste oil from construction vehicles and equipment will be collected in appropriate containers and transported offsite for recycling or disposal at an approved facility.

Individual subcontractors will be responsible for handling hazardous wastes resulting from their onsite activities. This responsibility includes the proper offsite disposal of such wastes.

4.1.2 ROADS

Main access to and from the site will be provided by an extension of the existing Caulkins access road from SR 710, southward along the west side of Caulkins and the ICL site property as shown on the Plot Plan, Figure 3.2.0-1. This road will be constructed per Martin County standards. It will extend around the south perimeter of the site and intercept the South West Farm Road, providing a public throughway between South West Farm Road and SR 710.

A secondary access road will be provided from the southern perimeter road into the power block area. Other maintenance roads within the site boundary will be constructed to provide access to equipment and remote areas as necessary.

Construction access will be provided by a new road within the easement for the rail spur between Caulkins and Florida Steel Corporation. A portion of this easement may be used for construction parking along with the main laydown/parking area. Construction personnel may also use the secondary plant entrance for access into the construction parking/laydown area.

4.1.3 FLOOD ZONES

The ICL site is located in Zone B (100- to 500-year floodplain) as defined by Flood Insurance Rate Maps (FEMA). No part of the ICL site is within the 100-year floodplain.

4.1.4 TOPOGRAPHY AND SOILS

The ICL site is relatively flat, with existing grade elevation ranging from approximately 32 to 35 feet mean sea level (MSL). The site is generally brush covered, with some lightly wooded areas, and is crossed by several surface runoff ditches. Some of these ditches contain standing water.

Excavations made on the site during construction will affect site runoff slightly in small, localized areas adjacent to the excavations. Existing ditches and ponds on the site currently collect stormwater; these elements will be maintained during construction. An existing ditch running north/south over the site will be relocated, but still maintained. More importantly, a detailed stormwater management plan will be implemented, involving construction of collection works and stormwater runoff ponds. The effect on runoff is, thus, expected to be minimal.

Site stripping operations will have an effect on percolation rates. Again, the effect will be on localized areas, since stripping will take place primarily where roads or structures are to be constructed. Consequently, percolation rates will be affected during construction only in these limited areas. After construction, open disturbed land not occupied by roads or structures will be planted with grass, restoring the previous percolation rates.

The site is currently vacant, removing any threat to existing structures from subsidence. Subsidence over the site, as a result of construction activity, will not likely occur due the lack of any significant causal mechanism. Pile driving can densify loose, upper deposits of sand, causing slight local settlement. The subsurface exploration shows that the upper sand deposits generally increase in density with depth, typically becoming medium to dense at a depth of about 5 feet. This soil is too dense to settle significantly under pile driving operations.

Sink hole formation takes place below the ground surface, by the dissolving of carbonate soils and rock by acidic water. As stated in Section 2.3.2, sink hole formation is not expected to occur in the site area, nor will it be enhanced or affected by construction activities.

To lower a soil deposit's bearing strength, in-situ shear strength must be lowered. Typical construction activities such as dewatering, pile driving, and the travel of heavy construction equipment will frequently densify sand soils, causing an increase in shear strength. Since the site's subsurface soils are almost exclusively sands, construction will, therefore, not cause a reduction of bearing strength.

Excavations made during construction can potentially affect the stability of adjacent existing soils. The only significant excavation planned is for the rail car unloading facility. This excavation will require extensive dewatering, and sidewall sloping or shoring. The safety of personnel working in and around this excavation will be ensured by the careful, thorough, and proper design of the dewatering and excavation support systems. When the excavation is made according to this process, with rigorous inspection to ensure safe construction, stability will not be a problem.

4.2 IMPACT ON SURFACE WATER BODIES AND USES

4.2.1 IMPACT ASSESSMENT

Possible surface water bodies affected by project development are the existing onsite drainage ditch, the St. Lucie Canal, seven wetland areas within the property boundary, and the TC/NS near the intake structure. It is the SFWMD's requirement that all drainage patterns return to pre-developed conditions and that peak discharges not be altered in the process.

Activities Within Surface Water Bodies

The only construction activities directly affecting surface water bodies are the rerouting of the existing drainage ditch and the construction of the intake structure. The drainage ditch rerouting will be completed very early in the project and care will be taken to maintain the existing water level, quantity, and quality of the discharge. Silt fences and straw bale dikes will be employed, as described in Section 3.8.4.2, where needed to filter runoff to the ditch. Velocities in the ditch will be at a minimum to deter sediment and erosion transport. Control measures will remain in place until the site runoff has stabilized in an acceptable manner in regard to sedimentation and erosion.

Rerouting of the existing drainage ditch will not have any significant impact on the offsite drainage. The rerouted portion of the existing drainage ditch will maintain existing hydraulic capacity. Post-development discharge from the site to the existing ditch will not exceed the pre-development peak discharge.

The underwater portion of the intake structure will be installed by constructing a temporary driven sheet pile cofferdam in the canal, excavating from within the cofferdam to install the intake pipes, and then backfilling to cover the pipes. Any leakage through the sheet pile wall will be into the cofferdam, and thus there will be no sediment flow to the outside of the cofferdam during construction.

Activities Affecting Discharge to Surface Water Bodies

Due to the large amount of earthwork required to raise the plant and coal storage/handling area elevations, stormwater runoff quality may be affected. Management, vegetative, and structural practices, as described in Section 3.8.4.1, will be implemented to mitigate adverse impacts on water quality during construction. These will include the control of sedimentation (erosion) by minimizing exposure of erodible soils, minimizing water velocity through use of milder slopes and diversion, use of grass and riprap covers, and channelization of stormwater runoff into sedimentation basins.

Stormwater management plans (Section 3.8.5) and sedimentation and erosion control plans (Section 3.8.4) for the ICL have been developed and will be implemented prior to and during earthwork. The stormwater management plan will utilize five stormwater detention basins, shown on Figure 3.8.2-1 and described in Section 3.8.5, which will act as sedimentation basins during the construction phase. Approximately 9 acre-feet of detention volume will be provided in the power block and coal handling areas. An additional 3.6 acre-feet of detention volume for the inactive coal pile runoff basin will also be provided.

During installation of the stormwater management system, measures taken to minimize the impact of surface water management activities will include:

- Mulching and seeding, with quick germinating varieties of grass, in all areas not subject to construction activities for more than 30 days

- Treatment of runoff from active construction areas by silt fences, gravel or rock filtration, straw bales, or other temporary erosion control measures

- Diversion of runoff from undisturbed areas around construction areas

- Use of physical soil stabilizers such as straw, wood chips, netting, or hay to protect exposed soils

- Installation of sediment filter devices where appropriate

The methods described in Section 3.8.4 have incorporated control measures to prevent impacts to wetlands from sediment-laden runoff.

4.2.2 MEASURING AND MONITORING PROGRAMS

No waters of the state will be affected during construction and/or operation of the facility as discussed in Section 4.2.1. Therefore, no measuring and/or monitoring programs are proposed.

4.3 GROUNDWATER IMPACTS

4.3.1 IMPACT ASSESSMENT

Section 4.1.1 describes the construction operations for the proposed project. As discussed, wastes will be generated during construction. In general, these wastes will consist of building materials which represent no threat to the groundwater system beneath the site. Small amounts of garbage, waste oil, and other potentially harmful compounds will also be generated. These wastes will be disposed of offsite, as described in Section 4.1.1, and pose no threat to the Surficial aquifer system.

During construction, it may also be necessary to provide temporary onsite storage facilities for fuels, solvents, etc. Potentially hazardous fluids such as these will be provided with secondary containment to protect the Surficial aquifer in the event of an accidental spill on the ground surface.

Excavations will occur at several locations across the project site. The deeper excavations will intersect the water table and require dewatering systems. The SFWMD requires that no dewatering operation may reduce the capacity of any existing permitted water user by more than 10 percent. Furthermore, dewatering systems may not reduce the hydrostatic head beneath wetland areas by 1 foot or more.

There are two excavations at the site which will utilize dewatering operations that could conceivably impact the Surficial aquifer. These are systems which will withdraw groundwater at rates of more than 25 gpm. The coal unloading building will have the deepest excavation (Figure 3.1.1-1, Site Plan). The excavation will be 20 feet wide, 50 feet long, and 40 feet deep at its deepest point.

The other excavation site to utilize a dewatering operation will only be about 14 feet deep. At this excavation, circulating water lines will be installed below ground, running between the pump house and the administration building (Figure 3.1.1-1, Site Plan). These lines will be placed in an excavation that is 400 feet long, 26 feet across at its widest point, and 14 feet deep.

Groundwater Modeling

The geology of the site and the water-bearing layers which underlie the site are described fully in Sections 2.3.1.2 and 2.3.2.1. The Surficial aquifer occupies the upper 120 feet of sediments which underlie the site. Based on site-specific data and published data from nearby sites (FPL, 1989), the Surficial aquifer may be characterized for modelling purposes as a three-layer system composed of two water-bearing zones and one intervening confining layer with parameters as follows.

LAYER	THICKNESS (feet)	TRANSMISSIVITY (gpd/ft)	STORATIVITY	V, PERMEABILITY (gpd/ft^3)
L1	30	3300	0.15	0.03
L2	55	1500	0.0004	0.002
L3	35	5600	0.00013	0.2

Dewatering operations to be conducted at the coal unloading excavation were simulated using the finite difference groundwater flow model, PLASM (Prickett and Lonnquist, 1971). The model was calibrated against a 3-day aquifer performance test conducted on the site (Section 2.3.2.1). The results of this simulation and a comparison with the aquifer performance test observations are included in Section 10.5.1. Section 10.5.1 contains a computer printout of all model input parameters as well as the simulation results.

The model assumes that grooved sheet piling (or similar construction techniques) will penetrate into layer 2 of the Surficial aquifer to a depth which is 6 to 8 feet below the bottom elevation of the excavation at the coal unloading location. The sheet piling will surround and completely enclose the excavation, thus preventing seepage from entering the excavation as horizontal flow from layer 1.

As shown on Figure 3.1.1-1, Site Plan, the coal unloading site is located about 200 feet northeast of a wetland. In order to minimize drawdowns within layer 1 and protect the wetland from measurable impacts, an infiltration gallery will be constructed midway between the wetland and the excavation site. Water from the dewatering system will be directed into the infiltration gallery to be discharged into layer 1 as seepage.

The dewatering system was simulated as one sump or well, placed at the center of the excavation and within the sheet piling perimeter. The bottom elevation of the excavation will be within layer 2 of the Surficial aquifer. When pumping begins, a cone of influence in layer 2 expands outward from the excavation until the total pumpage (approximately 65 gpm) is matched by an equal rate of leakage into layer 2 from layers 1 and 3.

Because layer 3 was excluded from the dewatering simulations, all seepage into layer 2 was assumed to be from layer 1, the unconfined aquifer, and therefore simulated drawdowns of the water table are actually greater than anticipated.

Three scenarios were simulated. Scenarios 1 and 2 simulate continuous dewatering for 180 days, the anticipated period of excavation, during the dry and wet seasons when recharge as precipitation is available to layer 1. These simulations indicate that the water table will not be lowered more than about 0.5 feet within a radius of 200 feet of the excavation. Scenario 3 simulated 90 days of continuous dewatering with no recharge to layer 1 except for seepage from the infiltration gallery at a rate of 3 gpm. The simulation indicates that dewatering operations can continue through 90 days of drought without lowering the water table as much as 1 foot at any location. Computer printouts of the 3 scenario simulations, with model inputs and simulation results, are presented in Section 10.5.1.

Based on the results of the computer simulation, including the utilization of sheet piling and an infiltration gallery during the excavation period, no adverse impacts to wetlands are anticipated. The nearest existing permitted groundwater users are located several thousand feet from the excavation site (Section 2.3.3). At this distance, the wells will not experience any significant reduction is capacity approaching the regulatory limit of 10 percent.

Dewatering operations to be conducted at the circulating water lines excavation were simulated using the analytical methods developed by Theis (1935). Dewatering along the 400-foot ditch was simulated as three 15 gpm wells and one 20 gpm well, spaced at 100-foot intervals and screened within layer 1 of the Surficial aquifer. Water from the dewatering system will be directed into a nearby storm water collection basin (Figure 3.1.1-1). Infiltration into layer 1 from this basin was simulated as three 10 gpm recharge wells and two 5 gpm recharge wells. The dewatering operations were simulated for 45 days, the approximate time needed to excavate the ditch and bury the lines. Figure 4.3.1-1 displays the results of the

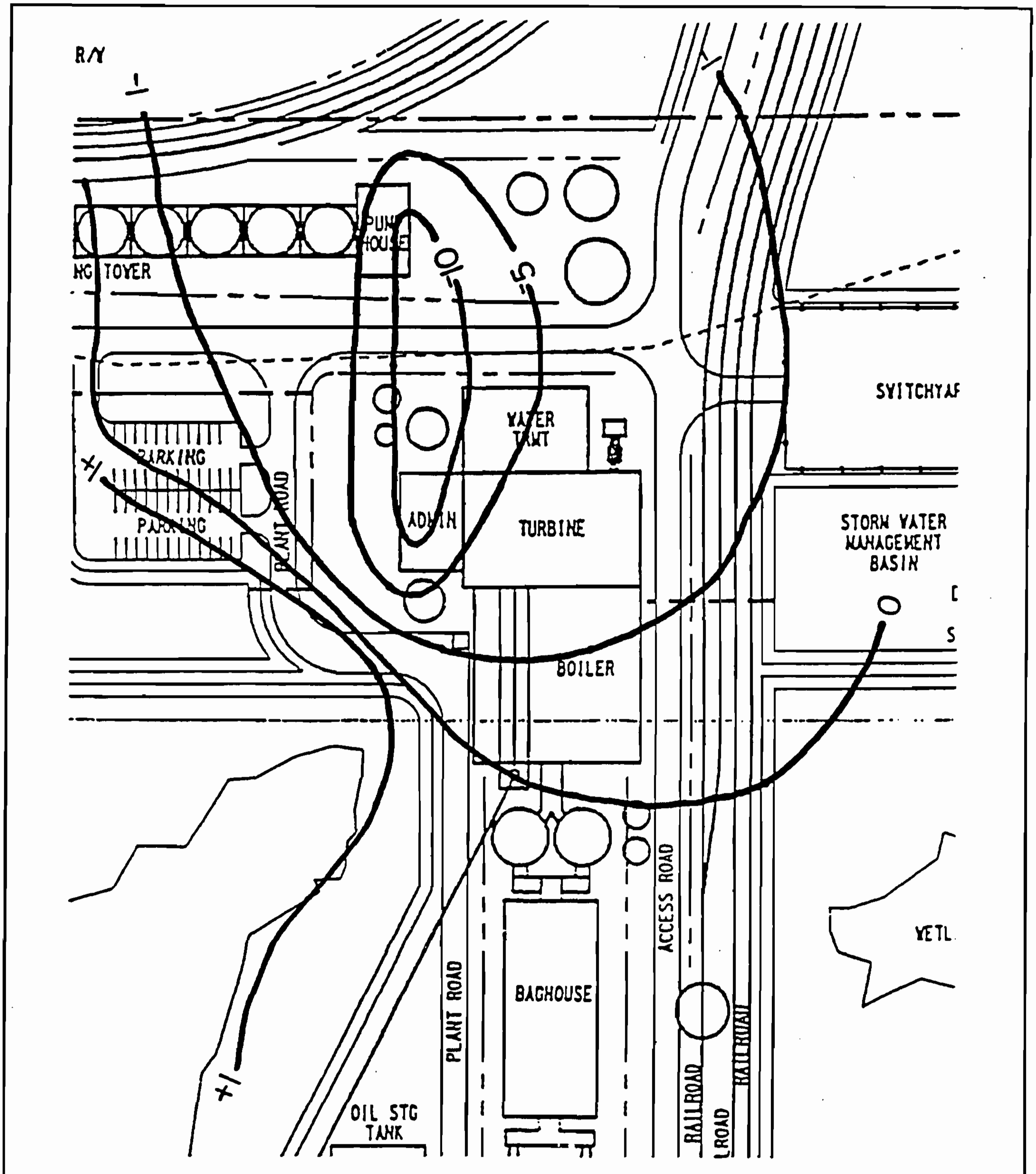

Figure 4.3.1-1.

PREDICTED CHANGE IN WATER TABLE ELEVATIONS AFTER 45 DAYS OF DEWATERING THE CIRCULATING WATER LINES EXCAVATION

Source: A. Campbell, 1990

INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

simulation. As shown, no significant impacts to the nearest wetlands will occur during this brief dewatering period.

To summarize, a finite difference groundwater flow model and analytical methods were used to simulate the proposed dewatering operations and assess groundwater impacts. Based on SFWMD criteria, no adverse impacts to wetlands will occur because of dewatering operations at the site. Furthermore, no measurable impacts to existing users are anticipated.

4.3.2 MEASURING AND MONITORING PROGRAMS

Dewatering activities are the only kind of construction operation that could possibly impact the Surficial aquifer in a measurable fashion. In addition to the existing onsite Surficial aquifer monitor wells located at the corners of the site (Section 2.3.2.1), additional observation wells will be placed between the proposed excavation sites to be dewatered and the nearest wetlands. Seasonal variations in the water table will be established before construction operations begin. Once construction has started, these observation points will be used to document that seasonal variations in the water table are not being affected by dewatering operations.

4.4 ECOLOGICAL IMPACTS

4.4.1 IMPACT ASSESSMENT

4.4.1.1 Site Construction Plan

A technical engineering description of the operation and maintenance of the 330 MW Indiantown Cogeneration, L.P. (ICL) Project facility is provided in Section 3.0. The general description of construction of the facility and associated impacts are provided in Section 4.1.

The ICL facility will be constructed over a 42-month period. For the purposes of this ecological impact assessment, the project is divided into four components:

- Power block
- Coal storage/handling
- Temporary construction laydown
- Cooling water storage pond

It can be assumed for the purposes of this impact assessment that all of the natural vegetation cover within these areas will be completely cleared.

4.4.1.2 Acreage Requirements

Table 4.4.1-1 presents the acreage requirements for the construction and operation of the ICL facility, along with the vegetation community types affected. The power block will occupy approximately 21 acres of pine flatwoods. Coal handling and storage facilities will occupy approximately 15 acres of pine flatwoods.

Approximately 0.3 acre of pine flatwoods will be required for the fuel oil storage and handling facility. The switchyard will cover approximately 0.94 acre of pine flatwoods. The cooling tower will cover approximately 0.93 acre of flatwoods. The

Table 4.4.1-1
ACREAGES OF VEGETATION COMMUNITIES TO BE IMPACTED, PRESERVED, AND RESERVED FOR POTENTIAL FUTURE USE OF THE ICL

	Vegetation Community					
	Pine Flatwoods	Wet Prairie*	Ruderal Land+	Total Uplands	Total Wetlands	Total Acreage
Project site	**199.6**	**24.4**	**8.0**	**207.6**	**24.4**	**232.0**
Power block	21.0	--	--	21.0	--	21.0
Coal storage/handling	15.0	--	--	15.0	--	15.0
Roads, railroads, miscellaneous	45.6	--	--	45.6	--	45.6
Temporary construction laydown area	12.0	--	--	12.0	--	12.0
Cooling water storage pond	25.0	--	--	25.0	--	25.0
Total potential impact area	118.6	--	--	118.6	--	118.6
Total preserve area	58.3	24.4	--	58.3	24.4	82.7
Total remaining area	22.7	--	8.0	30.7	--	30.7

Notes: The remaining areas of land that will not be impacted by the proposed development or preserved include existing land uses such as the transmission line right-of-way and roads or pine flatwoods that are for potential future use.
*Wet prairie includes both the wetlands and the manmade ditch onsite. The ditch, which encompasses approximately 1 acre, will be rerouted and then maintained onsite.
+Ruderal land includes the existing transmission line right-of-way, roads, and clearings.

Source: Bechtel, 1990

temporary construction laydown area will cover approximately 12 acres of flatwoods. Finally, the cooling water storage pond located at the northwestern corner of the plant site will cover approximately 25 acres of pine flatwoods.

Approximately 8.3 acres of pine flatwoods will be preserved as natural, 50-foot contiguous buffers around three wet prairie areas located in the central portion of the development and another wet prairie site on the northwest corner of the property. The balance of the 50 acres of flatwoods will also be preserved onsite as visual screening and upland wildlife preserve. Approximately 23.4 acres of wet prairie within the project site environs will also be preserved. An additional acre of man-made ditch will be rerouted and then maintained on the project site. Figure 4.4.1-1 provides a map of the preserved uplands and wetlands on the ICL site.

The remaining acreage includes existing transmission line right-of-way and roads that will be maintained. Approximately 22.7 acres of pine flatwoods will also remain on the site for potential future plant use.

4.4.1.3 Environmental Management and Protection Plans for Construction

The following categories identify the environmental management protection procedures to be followed to protect or otherwise limit the impact to the surrounding ecological resources before, during, and after project construction:

- Clearing and grubbing
- Site restoration
- Soil erosion and sedimentation control measures
- Wetland protection

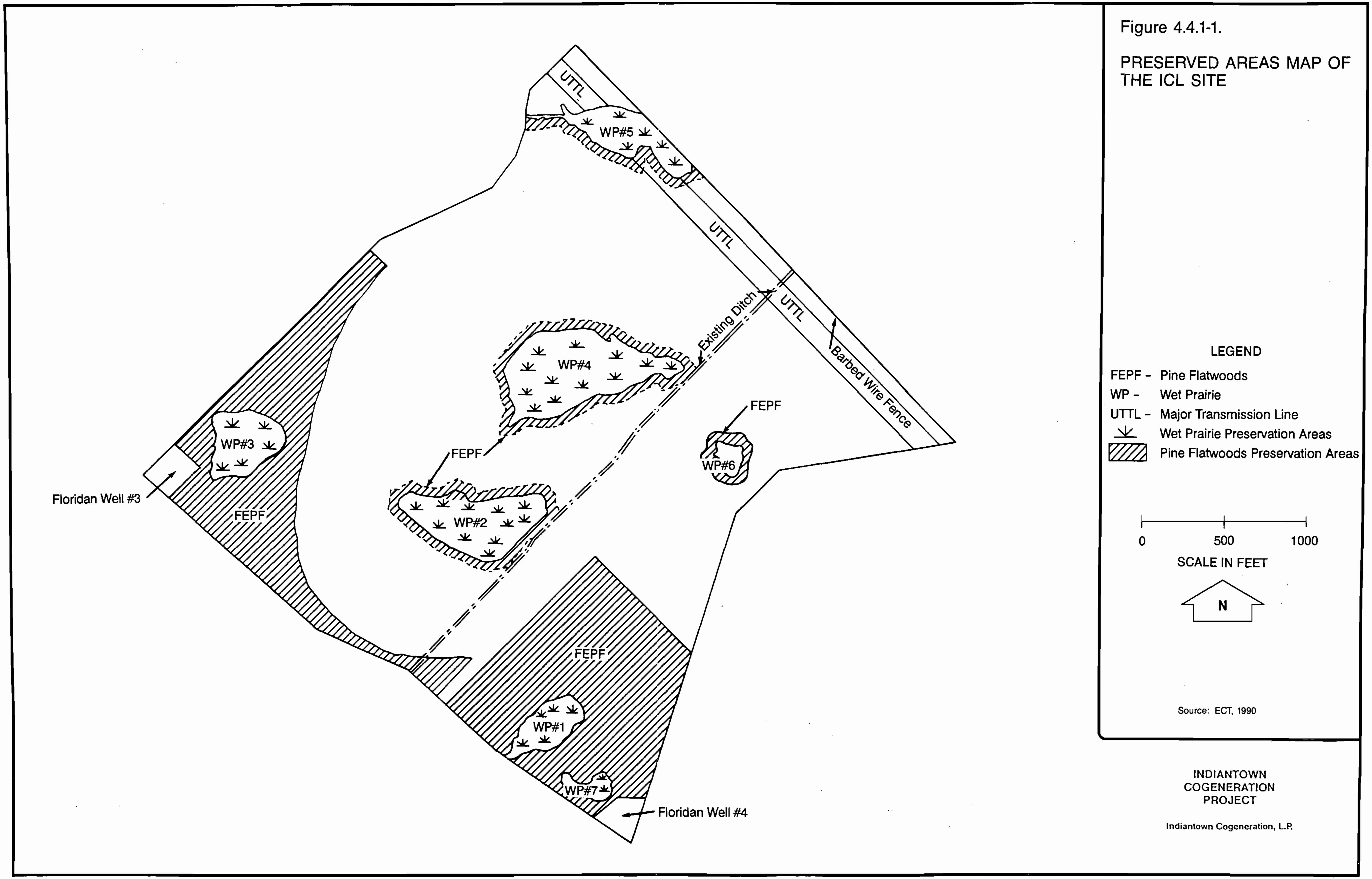

Figure 4.4.1-1.

PRESERVED AREAS MAP OF THE ICL SITE

INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

Clearing and Grubbing

1. A survey will be made of the area to be disturbed by project construction (i.e., the areal extent of clearing and grubbing as identified on project engineering drawings). The boundaries of this area will be clearly marked on site plans and in the field before any construction activity commences. Clearing and grubbing or other construction activities beyond this marked area will be prohibited.

2. The prevention of damage to vegetation outside construction areas will be emphasized in all construction operations, and careless or needless equipment operation will be avoided. Areas to be avoided by construction will have barricades installed to limit activities therein.

3. Debris derived from clearing and grubbing will be hauled offsite.

4. To ensure the least possible damage to the onsite vegetation, the use and storage of vehicles, equipment, and materials will be restricted to those areas which will be permanently disturbed by required designated construction activity or earthwork operations, or the temporary construction laydown area.

Site Restoration

1. ICL will require that contractors attain the following goals for site restoration after construction is completed:

   - Timely site stabilization of disturbed soil

   - Timely restoration of disturbed or altered areas through vegetative plantings appropriate to the season and soil type

2. Fill slopes will be sodded or seeded and mulched.

Soil Erosion and Sedimentation Control Measures

The soil erosion and control measures to be used during construction are discussed in detail in Section 3.8.4.1. Highlights of these measures include the following:

1. Barriers are planned and will be maintained to serve a continuing functional role in erosion control before, during, and after construction until the areas are stabilized. The proposed barriers will consist of bales of straw or other suitable filter material.

2. Stabilization techniques will be used to establish a stabilized working surface for construction, where necessary.

3. Contractors will be required to implement temporary stabilization measures to minimize loss of topsoil, excess sedimentation to the drainage ditch, and potential deterioration of water quality.

4. Prior to construction, contractors will be required to submit plans for accomplishment of temporary and permanent erosion control work. These plans will detail the erosion controls for clearing and grubbing, excavation, and final grading within access and haul roads, the work site, and the temporary construction laydown area.

5. All disturbed areas not otherwise stabilized will be mulched and/or seeded within 15 days of exposure or as soon thereafter as seasonally practicable, except in areas where construction will resume within 30 days. Areas to be seeded will employ quick-germinating varieties, such as winter rye grass, which provides temporary cover and soil retention properties.

6. All exposed drainages will be sodded or mulched and seeded immediately after each construction phase or disturbance.

7. Physical soil stabilizers will be used, where appropriate, to protect exposed soil from falling or flowing water (e.g., straw, wood chips, netting, hay, etc.).

8. Sediment filter devices will be installed to prevent siltation, accumulation, or debris.

9. Runoff from the disturbed areas will be conveyed to the detention basins prior to release to the natural runoff.

10. After the completion of the construction, the detention basins will be cleaned, if necessary, and used for operations stormwater management.

Wetland Protection

1. A 50-foot natural vegetation buffer will be established along the jurisdictional wetland boundary of three wet prairies centrally located close to project development and another wet prairie situated at the northwestern corner of the project site. The 50-foot setbacks will be surveyed and a barricade installed along the surveyed lines.

2. No disturbance of any kind will be allowed within the barricaded setback.

3. The other wet prairie areas located further away from site development are situated within natural pine flatwoods that will be preserved. There are significant expanses of upland preserved areas surrounding these wet prairies (i.e., greater than 50 feet landward of wetland jurisdictional

boundaries). Upland preserve areas surrounding these wetlands will also be barricaded.

4. For more information regarding wetland and upland preserve protection, refer to Section 4.4.1.4, Vegetation Communities, under Preservation Program.

4.4.1.4 Vegetation Communities

Project Impact

Project construction will remove all of the existing natural vegetation located in the areas to be cleared and grubbed. Table 4.4.1-1 specifies the types and acreages of vegetation to be affected. Of the 232 acres of project site, about one-half of the site's acreage will be impacted. Of the approximately 118.6 acres to be affected by project construction, almost all of it consists of pine flatwoods (minor areas of less than 1 acre of clearings, trails, and roads were not subtracted from flatwoods acreage as ruderal land).

No wetlands, except the drainage ditch to be rerouted, will be encroached upon during construction and operation of the plant. The remainder of the project area (49 percent or 113.4 acres) is comprised of either preserved pine flatwoods (50 acres) and preserved wet prairie/ditch (24.4 acres), or land left for potential future plant use (22.7 acres). An additional portion of the pine flatwoods will also be preserved (8.3 acres) consisting of natural upland buffers to three of the wet prairie areas located in the center and one wet prairie situated at the northwestern corner of the plant site. The pine flatwoods to be developed on the ICL site are locally and regionally common in Martin County.

Preservation Program

The existing stresses to the vegetation on the project site have occurred as a result of cattle grazing, alteration of hydrologic regimes, and creation of disturbed areas by road and transmission line corridor construction and off-road vehicle trails. Though impacts to these natural communities are apparent, the existing communities can be considered to exhibit moderate to good ecological diversity and function. In addition, a significant portion of the site (82.7 acres or 36 percent) will be preserved. This includes all of the wetlands/ditch (23.9 acres) and the 58.3 acres (25 percent of the total pine flatwoods acreage) of the pine flatwoods (see Figure 4.4.1-1).

ICL also proposes to re-route portions of the existing drainage ditch (approximately 1 acre) traversing the central portion of the site. This should enhance the hydrology of the adjacent wet prairie by improving surface water overland flow. This wet prairie had some wetland plant elements displaced by upland species, and the re-routing of the ditch may result in a return of more desirable hydric species.

Exotic vegetation on the ICL site is neither widespread nor abundant. Some punk tree and Brazilian pepper were observed in the pine flatwoods. These will be removed. Exotic plants are scarce to non-existent in the wet prairies. Removal of exotic vegetation will not require revegetation with native flora due to the limited extent and numbers of these noxious plants.

A major goal of preservation management is maintenance of the existing natural condition of upland and wetland communities, particularly wetland hydroperiods. To do this, surface water and groundwater regimes must be artificially maintained or restored. To the extent feasible, or when necessary, the wetland areas will be incorporated into the project's surface water management plan. Through the use of Best Management Practices (BMPs), hydroperiods of affected wet prairies can be maintained without excessive, unseasonal flooding or drying.

A potential post-construction impact to management of preserve areas is disposal of solid wastes and coal storage. All solid wastes generated by operation of the ICL facility will be removed for offsite disposal. Thus, no impacts to preserved areas onsite due to solid wastes will occur. The active coal pile will be stored in an enclosed facility and the coal conveyor to the plant will be totally enclosed to keep fugitive coal dust at a minimum. In addition, the inactive coal storage pile will be lined and grassed over. Any runoff and leachate from the pile will be collected in a lined basin, treated, and recycled for process water needs.

In addition, the following preservation program management guidelines will be adhered to:

1. All required grade changes (i.e., railroad and road) will be engineered so that any cut or fill will meet existing grade without encroaching into the preserve area.

2. All exotic vegetation will be removed. Stumps will be treated with a contact herbicide to prevent regrowth.

3. All of the preserve areas boundaries will be surveyed. The surveyed preserve areas will then be delineated/ protected in the field using barricades along the surveyed boundaries prior to any clearing activities.

4. Prior to any clearing, the barricades will be inspected to ensure proper placement and construction by the Martin County Growth Management Department.

5. Barricades will be constructed onsite and maintained intact for the duration of construction.

6. Where areas are proposed for clearing (i.e., building envelope, utilities and drainage, road right-of-way, etc.), the barricades will be offset at least 10 feet outside the preserve areas or placed at the dripline of the canopy trees, whichever is greater.

7. Individual trees or groups of vegetation that are to be saved will also be barricaded according to the previously mentioned guidelines.

8. All native vegetation which is not located in areas requiring their removal as part of the development plans shall be retained in their undisturbed state.

9. Advisory or warning signage will be posted.

10. Contractors will be provided a set of the preservation program guidelines and warned that any violation of these guidelines and damage to, or destruction of the preservation areas will result in remedial action.

11. Prohibited activities in the preserve areas will include: removal or destruction of native vegetation; dumping of fill, trash, or building and construction materials and debris; excavation; recreational vehicle use; or any activities detrimental to drainage flood control erosion control, or wildlife habitat conservation.

4.4.1.5 <u>Aquatic Systems</u>

All of the wet prairies on the project site will be preserved and protected from project construction impacts. Although the drainage ditch will be rerouted on the project site, the existing drainage pattern will be maintained and enhanced through a surface water management plan. During the ditch realignment, special precautions will be taken to safeguard the downstream water quality from deterioration through proper erosion and sedimentation control practices.

Since no aquatic systems will be significantly affected by the proposed project, no project impacts to aquatic ecological resources are expected before, during, or after construction.

4.4.1.6 Wildlife Resources

The principal impact on wildlife associated with project development will be the loss of up to approximately 118.6 acres of onsite habitat. Because pine flatwoods are the only dominant habitat to be affected, and pine flatwoods are regionally common, the partial clearing of this habitat will have insignificant impacts on regional wildlife populations.

Although the more non-motile species will be lost during construction, mammals and birds are expected to be displaced to the surrounding natural pine and wet prairie areas. It is not expected that individuals of species populations which breed or winter onsite will be displaced. With the exception of the white-tailed deer, eastern cottontail, raccoon, opossum, bobcat, gray squirrel, gray fox, feral pig, mourning dove, and bobwhite, recreational and commercially important animal presence on the project site and vicinity is low. Because hunting is currently precluded on the site, project impacts on wildlife as a local recreational or commercial resource will not occur.

4.4.1.7 Threatened or Endangered Species

The ICL project will not affect known breeding populations of animal species which are listed as threatened, endangered, or species of special concern (Table 2.3.6-2). Wading birds visit the project area occasionally for feeding; however, no current breeding populations are known to occur in the project site area.

Although alligators, indigo snakes, and gopher tortoises are expected to occur within the site environs, no significantly adverse impacts to these listed reptile species populations would be expected from project construction. Bachman's sparrows, loggerhead shrike, and other migratory birds that utilize site habitats will find suitable and abundant habitat adjacent to the project site during and after construction. No other listed animal species have been observed or are known to inhabit the project site or its immediate environs.

No endangered or threatened plant species listed by USFWS on Table 2.3.6-1 were located on the project site. Only three fern species listed as threatened by FDACS were discovered within the wet prairies and ditch on the project site. Although these ferns species could also occur within the extremely small, wet weather depressions in the pine flatlands to be affected by development, no significant impacts to local species population are anticipated as a result of project construction. Even if some individuals of these listed fern species should be affected, it would not be considered to be a significant impact because of the following factors:

1. The fern species on Table 2.3.6-1 are listed as threatened by FDACS primarily to discourage commercial exploitation, rather than providing a designation of the current species population status.

2. The fern species are widespread in freshwater wetlands throughout Florida.

3. The fern species are common locally and, therefore, the loss of some individuals will not affect the status of regional populations.

The Florida coontie (Zamia pumila) may occur onsite based on habitat suitability and range of distribution. However, no sightings of this conspicuous cycad occurred during numerous surveys of the impact areas of the project site. Therefore, no impacts to the Florida coontie would be expected from project development. In summary, protected species populations of wildlife and plants should not be significantly affected by project construction.

4.4.2 MEASURING AND MONITORING PROGRAMS

4.4.2.1 Project Area

No monitoring of the project area is planned.

4.4.2.2 Preservation Area

Since project construction and operation should not result in direct or significant secondary impacts to the surrounding vegetation, monitoring of the pine and wet prairies to be preserved on the project site is not considered necessary.

4.5 AIR IMPACT

4.5.1 EMISSION SOURCES

During the construction period, unavoidable air pollutant emissions are likely to occur from various construction-related activities. The most prevalent construction emissions are fugitive dust. However, minor emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter, and volatile organic compounds (VOCs) from equipment exhaust are also likely during construction.

Fugitive Dust

Fugitive dust is generally defined as natural and/or man-associated dusts that become airborne due to the forces of wind or human activity. Construction-phase fugitive dust emissions are generated during site clearing, grubbing and grading, excavation, and vehicular activities.

The quantity of fugitive dust emitted by the site construction vehicular traffic depends on a number of factors, including the frequency of operations, specific operations being conducted, weather, and soil conditions. Many of the construction operations, such as land clearing and foundation excavation, will be intermittent and of a temporary nature. Fugitive dust emissions due to concrete batching will not occur during construction. Concrete will be brought to the site from nearby commercial batching facilities.

Other Air Pollutant Emissions

It is anticipated that the total gaseous emissions released into the atmosphere during construction will be small. Potential sources of VOC emissions are evaporative losses associated with onsite painting, refueling of construction equipment, and the application of adhesives and waterproofing chemicals. The frequency and extent of these activities are limited.

Exhaust emissions from construction equipment will also contain small amounts of NO_X, SO_2, CO, particulate matter, and VOCs resulting from incomplete combustion of fuel. However, due to the nature of heavy-duty, diesel-powered construction vehicles, which allow for more complete combustion and use less volatile fuels than spark-ignited engines, these emissions are relatively low.

4.5.2 AIR QUALITY CONTROL METHODS - BEST MANAGEMENT PRACTICE

The typical approach used to reduce fugitive dust emissions during construction activities of this type is water spraying. Reductions of 50 percent are readily achievable by watering paved surfaces, and this can be increased to about 75 percent when followed by mechanical sweeping. Emissions from unpaved roads can be reduced 50 to 75 percent by water spraying. In both cases, the degree of control achieved depends on the application intensity and the number of vehicle passes between applications, as well as climatological factors (e.g., rainfall, evaporation rate, time of year) (EPA, 1984). In addition, a speed reduction program may further reduce emissions from unpaved surfaces by 25 to 80 percent (Ohio EPA, 1980). Trucks can be covered or the material wetted to substantially reduce the amount of material blown from the trucks. In addition, wheel washing may be implemented to prevent tracking soil onto paved surfaces.

Emissions from the storage of excavated materials or backfill and associated traffic can be controlled by up to 90 percent (EPA, 1988) by either covering the storage piles or treatment with surfactants, and by the application of a watering program on the associated service roads.

Contractors will be instructed to comply with any applicable state or local regulations governing open burning. Areas disturbed during construction will be seeded to stabilize or restore the soil surface.

4.5.3 AIR IMPACT ASSESSMENT

Air quality impacts resulting from construction activities will tend to be short-term and localized. Fugitive dust created by construction activities is made of relatively large particles. Therefore, the majority of these particles will settle near the construction activity areas. Site grading and excavation activities are of short-term nature; thus, fugitive dust emissions created by these activities have very little threat to long-term ambient air quality levels in the proposed ICL site area. Numerous abatement measures as discussed in Section 4.5.2 can be taken if necessary, as part of best management practice to further minimize any of these minor short-term impacts from construction-related activities.

Similarly, gaseous pollutants generated by the diesel-powered construction equipment are also of short-term nature. Diesel-powered construction equipment is not a significant pollutant emitter in general, if it is properly maintained and periodically inspected.

In summary, air quality impacts during the construction phase of the proposed ICL project will be temporary and generally minor. The impacts will cease when construction activities are terminated for operation. Therefore, the proposed project is not expected to have any significant construction-related air quality impacts to the public health and welfare.

4.6 IMPACTS ON HUMAN POPULATIONS

4.6.1 PROXIMITY OF RESIDENTIAL AREAS

As previously discussed in Section 2.2.3.3, the majority of lands within the 5-mile study area are agricultural or undeveloped. The exceptions to these agricultural or undeveloped areas within the 5-mile study area include the existing FPL Martin power plant site, the existing industrial developments located in the immediate vicinity of the ICL site, and areas within the unincorporated community of Indiantown. Because the properties directly adjacent to the ICL site are either industrial or agricultural in nature, no residential developments are located directly adjacent to the site.

The majority of residential populations within the 5-mile study area are located in the unincorporated community of Indiantown, approximately 3 to 4 miles from the site. As previously described in Section 2.2.7.4, the Indiantown community contains a total of 1,627 dwelling units, of which 1,443 or, 88.7 percent, are considered to be in good condition. The largest residential district in Indiantown is the Indianwood mobile home development. Indianwood currently is planning to expand an additional 1,465 mobile home units on 565 acres (Indiantown Action Plan, 1990).

With the exception of the previously described residential areas within Indiantown, the remainder of the 5-mile study area contains relatively few residential structures. Utilizing 1989 tax roll data obtained from the Martin County Property Appraiser's Office, it was determined that there are 109 dwelling units within the 5-mile study area that are outside Indiantown. The population estimate for these 109 dwelling units, based on the statewide average of 2.47 persons per household (U.S. Department of Commerce, 1988), is 269 persons.

Because the majority of residents live over 2 miles from the site, the noise from construction of the site will have very little impact on the community. For those residences that are closer to the site, the fact that construction is projected to occur during a normal 40-hour work week and that there will be no blasting onsite, will result in low impacts to this nearby area.

4.6.2 CONSTRUCTION WORKFORCE

Construction of the ICL facility is anticipated to cover a period of 42 months, commencing in July 1992, and ending in December 1995. The last 6 months of this time period will be concerned with startup activities for the plant.

Table 4.6.2-1 shows the projected construction schedule over its 42-month duration. This schedule is based on a single-shift operating 40-hour work weeks. However, due to unanticipated and uncontrollable delays due to weather and equipment deliveries, the temporary implementation of shift work may be required to keep the project's construction on schedule. The construction workforce is expected to peak at 800 persons for 4 to 6 months during the third year of construction.

The commuting distance for this construction workforce is anticipated to be between 30 and 60 miles. However, construction workers could possibly commute as far as 100 miles, which is not considered to be unusual. Thus, the construction workforce could be drawn from Martin, Okeechobee, St. Lucie, and Palm Beach Counties, but may also be drawn from the Fort Lauderdale and metropolitan Miami areas. However, the majority of the construction workforce is expected to be drawn from the urban areas within 60 miles.

Though this workforce is predicted to commute, ICL will encourage carpooling and will study the possibility of utilizing private transit bus service for construction workers to reduce the number of vehicles transporting construction workers to the ICL site.

Table 4.6.2-1
CONSTRUCTION WORKFORCE INVOLVED IN THE ICL PROJECT

Year of Construction	Time Period	Number of Construction Workers
1	07/92 - 12/92	200
2	12/92 - 12/93	400
3	12/93 - 12/94	600*
4	12/94 - 12/95	200

*Construction workforce is expected to peak at 800 employees for 4 to 6 months during this time period.

Source: ICL, 1990

4.6.3 CONSTRUCTION WORKFORCE IMPACTS ON HUMAN POPULATIONS

Because properties directly adjacent to the ICL site do not contain residential developments, no impacts to residential populations are predicted in the immediate vicinity of the ICL site.

Impacts to human populations resulting from the construction workforce are expected to result from the influx of people and of the indirect population required to service and support the construction workforce. However, as stated previously, most of the construction workforce is expected to commute daily from their existing residences. Thus, in-migration to the local area due to the construction workforce is expected to be minimal and any impacts to human populations will also be minimal. A detailed analysis of economic, employment, transportation, housing, and community services impacts during construction of the ICL project is found in Section 7.0.

4.7 IMPACT ON LANDMARKS

As previously described in Section 2.2.5, only one area valued for its natural, scenic, or cultural significance is located within the 5-mile study area of the ICL site. This natural feature, Barley Barber Swamp, is located at the extreme western portion of the 5-mile study area, adjacent to the existing FPL Martin power plant cooling pond, approximately 4.5 miles west of the ICL site.

Construction at the ICL site is not expected to have any affect on this natural feature. Surface water quality (see Section 4.2.1) will not be adversely affected during construction. Groundwater effects (see Section 4.3.1) should be limited to onsite dewatering during construction. Dust suppression measures which will be implemented during the construction at the ICL site (see Section 4.5) will be adequate to maintain state air quality standards. Construction activities will not be visible from Barley Barber Swamp, and access will not be affected.

4.8 IMPACTS ON ARCHAEOLOGICAL AND HISTORIC SITES

A summary of the evaluation of archaeological and historic sites within the boundaries of the ICL site was previously presented in Section 2.2.6, and a copy of the cultural resource assessment is appended in Section 10.8. This assessment found no previously recorded archaeological sites and a low probability of finding additional historically significant resources within the ICL site. No archaeological or historic sites eligible for registration in the National Register of Historic Places were found (Piper, 1990).

In the event that a potentially significant archaeologic or historic resource is discovered during construction, those construction activities which may potentially disturb these finds will be halted until their potential significance can be determined by a professional archaeologist. If the materials are believed to be significant, the State Historic Preservation Office (SHPO) will be contacted to determine appropriate mitigation measures.

4.9 SPECIAL FEATURES

No special features as described in the FDER SCA guidelines are expected to be associated with the construction of this project.

4.10 BENEFITS FROM CONSTRUCTION

Benefits resulting from the site preparation and construction at the ICL site are expected to include increased employment opportunities, and additional county revenues.

The construction of the ICL project will provide many employment opportunities within Martin County, adjacent counties, and the region. As previously described in Section 4.6.2, the construction is scheduled to commence in July 1992, and end in December 1995. The construction workforce is expected to peak at 800 employees for 4 to 6 months during the third year of construction. Many of these construction positions will be relatively high-paying skilled positions. A detailed analysis of the socioeconomic benefits resulting from the construction of the ICL project is provided in Section 7.0.

4.11 VARIANCES

There are no variances from applicable standards due to construction activities.

REFERENCES

Section 4.3.1

FPL, Martin Coal Gasification/Combined Cycle Project Site Certification Application and Sufficiency Responses, 1989.

Prickett, T. A., and C. G. Lonnquist, Selected digital computer techniques for groundwater resource evaluation. Illinois State Water Survey Bulletin 55, 1971.

Theis, C. V., The relationship between lowering of piezometric surface and the rate and duration of discharge of a well using ground-water storage. Trans. Am. Geophy. Union, Sixteenth Annual Meeting, Part 2, 1935.

Section 4.5.2

U.S. Environmental Protection Agency (EPA) 1988 Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, AP-42 Fourth Edition, Supplement A, Office of Air Quality Planning and Standards, Research Triangle Park, NC, October.

U.S. Environmental Protection Agency (EPA), 1984. Cost Estimates for Selected Fugitive Dust Controls Applied to Unpaved and Paved Roads in Iron and Steel Plants, Final Report, prepared by Midwest Research Institute for EPA Region V, EPA Contract No. 68-01-6314, April.

Ohio Environmental Protection Agency (Ohio EPA), 1980. Reasonably Available Control Measures for Fugitive Dust Sources, Office of Air Pollution Control, September.

Section 4.6.1

Hahn and Company. 1990. Indiantown Action Plan. Prepared for the Martin County Growth Management Department.

U.S. Department of Commerce, 1988

Section 4.8

Piper Archaeological Research, Inc. 1990. Cultural Resource Assessment Survey of the Proposed Martin County Power Plant Site and Pipeline Right-of-Way, Martin County, Florida.

5.0 EFFECTS OF PLANT OPERATION

5.1 EFFECTS OF THE OPERATION OF THE HEAT DISSIPATION SYSTEM

5.1.1 TEMPERATURE EFFECT ON RECEIVING BODY OF WATER

Since treated wastewater will be discharged to an injection well, this section is not applicable.

5.1.2 EFFECTS ON AQUATIC LIFE

Since a heated effluent will not be released to a receiving body of water, this section is not applicable.

5.1.3 BIOLOGICAL EFFECTS OF MODIFIED CIRCULATION

This section is not applicable since a heated effluent is not discharged to a receiving body of water. The design of the intake structure to minimize effects on the aquatic environment is discussed in Section 3.5.1.1.

5.1.4 EFFECTS OF OFFSTREAM COOLING

5.1.4.1 Proposed System

The heat dissipation system proposed for the Indiantown Cogeneration, L.P. (ICL) project will be a linear mechanical draft cooling tower.

The proposed tower will be equipped with a bank of ten cells to meet the closed-loop cooling requirements of the plant. Tower design parameters are presented in Table 5.1.4-1.

The drift loss rate of the proposed tower is 0.002 percent or 5.3 gallons per minute (gpm). Under normal operation, the total dissolved solids of the circulation water is about 2,800 milligram per liter (mg/l). During periods of extended drought (i.e., a once in 10-year frequency for a maximum of 3 months), the backup cooling water from the Floridan aquifer could result in a total dissolved solids concentration in the circulating water as high as 16,200 mg/l. For the cooling tower impact assessment, only the normal operating conditions were analyzed because the backup water source is used infrequently.

The analyses showed that:

- There will be no impact on the visible plume on air traffic in the area.

- There will be no impact from ground fogging on the visibility along nearby roads.

- There will be no icing conditions associated with the freezing of vapor plume and drift deposition on surrounding areas.

- The impact due to deposition of the drift on agricultural and citrus land and orchards will be minimal.

Table 5.1.4-1
ICL MECHANICAL-DRAFT COOLING TOWER DESIGN PARAMETERS USED IN MODEL

Number of Cells	10
Heat Load	1,655 MMBtu/Hr
Circulating Water Flow Rate	265,000 GPM
Design Wet Bulb Temperature	80 °F
Approach	10 °F
Range	90 °F - 102 °F
Air Flow Rate Per Cell	1,575,000 ACFM/Cell
Drift Loss Rate	0.002%
Tower Dimension	60'x 600'x 56'
Fan Diameter	32.8'

Source: ICL, 1990

5.1.4.2 <u>Identification of Potential Impacts</u>

The proposed cooling tower will emit moisture into the atmosphere in the form of water vapor and water droplets, defined as drift loss for the facility. If the ambient air is cold and/or moist, a portion of the emitted water vapor will condense to form water droplets. This is seen as a visible white plume emanating from the cooling tower. Under most conditions, the plume evaporates as it moves downwind because of mixing with unsaturated air and from adiabatic heating. The frequency, persistence, and size of a visible plume depends on the type of cooling system and the local climate. An entire visible plume or a portion of a visible plume can be brought to the ground through high winds or turbulent eddies. Ground-level fogging can be produced from a cooling system plume when the visible plume reaches the ground.

As the normal service and circulating water flows through the fill section of the cooling tower, the impact of the falling water on the splash bars create small water droplets, some of which are carried away by the air stream moving through the tower. These entrained droplets, or drift which leave the cooling tower, contain dissolved solids that may cause a buildup of salt concentration in the soil and/or deposit on the surface of nearby vegetation. Therefore, operation of the cooling system has the potential to cause impacts on soil and vegetation in the surrounding areas. In addition, operation of a cooling system at sub-freezing temperatures can also produce ground-level icing.

5.1.4.3 <u>Assessment Methodology</u>

The EPRI-sponsored Seasonal/Annual Cooling Tower Plume Impact model (EPRI, 1984) was used to quantify the impacts. This computer code is an outgrowth of an earlier model evaluation study carried out by Argonne National Laboratory (ANL). Improved plume and drift models in the code have been calibrated with existing field and laboratory data and then subsequently verified with new data not included in the calibration process. This model has been widely used in preparing environmental assessments of cooling towers by utilities and their consultants. This program can predict the seasonal and annual impacts of the cooling tower plume's potential for drift, icing, and fogging.

The SACTI model is used to calculate plume dispersion and drift deposition for the proposed cooling tower. The same 5-year set of meteorological data (1982-1986) collected at the West Palm Beach NWS station was used for the air quality analyses in Section 5.6 and with the SACTI model to estimate cooling tower impacts. The cooling tower parameters that are modeled to determine hours of fogging, hours of icing, and potential salt deposition are presented in Table 5.1.4-1.

The spatial variation of the drift deposition rate is strongly dependent on the droplet size distribution. The larger droplets in the plume fall to the ground closer to the tower than the smaller droplets. Since there are no drift droplet size distribution data available for the proposed cooling tower, the drift spectrum provided in the Users Manual of the SACTI model was used (see Table 5.1.4-2).

5.1.4.4 <u>Impact Assessments</u>

The following subsections discuss the assessment of environmental impacts associated with operation of the ICL plant cooling tower. Climatological effects addressed include enhanced frequencies of fogging and icing, their extent and duration, and potential obstruction to ground and airborne traffic. The potential for impacts to soils and vegetation in the site area, due to cooling tower salt drift deposition, is also discussed.

<u>Fogging Potential</u>

The visible plume may reduce visibility if it crosses the path of ground-based or air traffic. The only nearby public road is U.S. Route 710 (see Figure 5.1.4-1). Its closest approach to the plant site is at least 750 meters to the northeast. At this distance, the SACTI model predicts a plume height of about 150 meters above the

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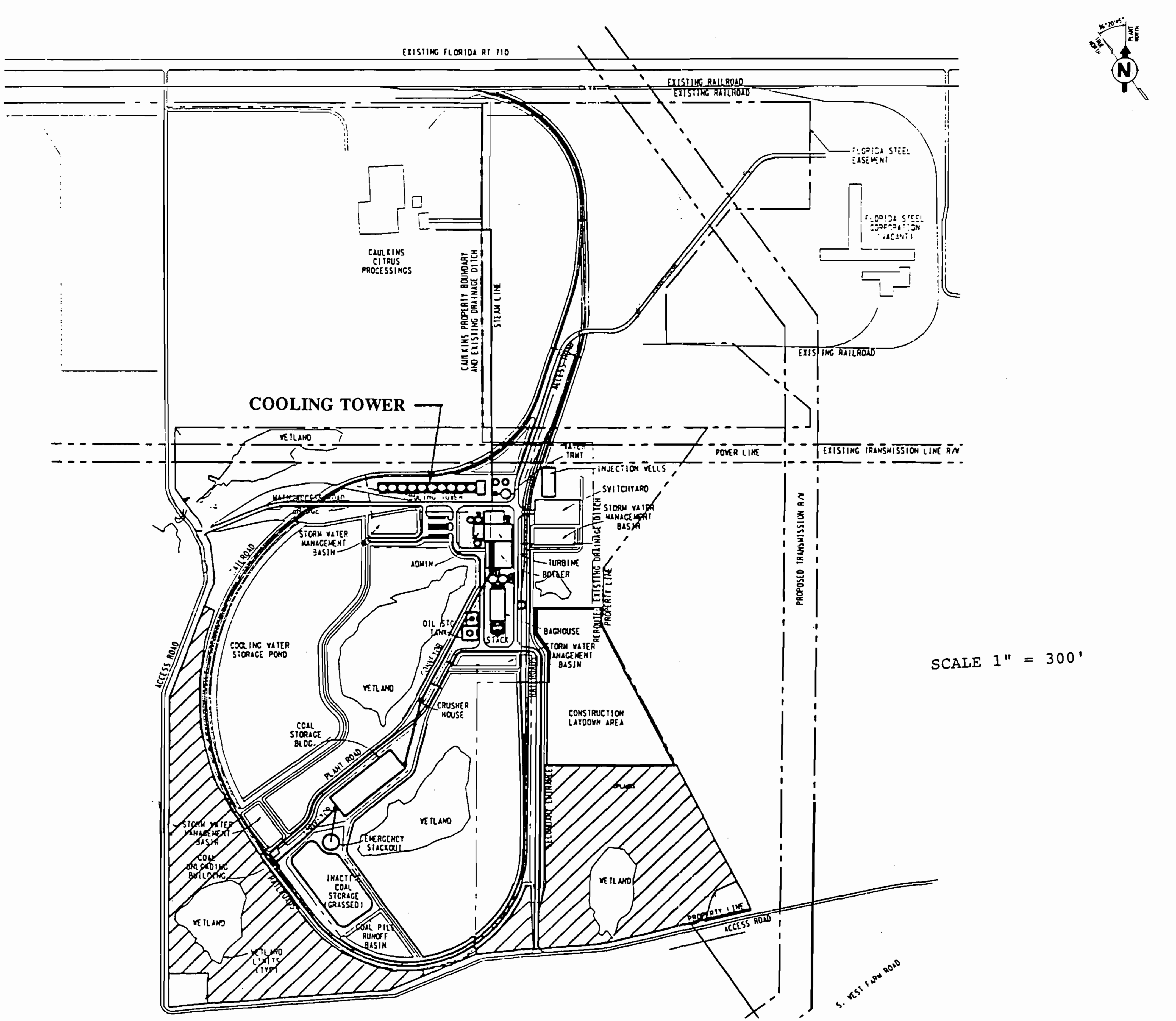

Figure 5.1.4-1.

COOLING TOWER LOCATION

Source: Bechtel, 1990

INDIANTOWN
COGENERATION
PROJECT

Indiantown Cogeneration, L.P.

TABLE 5.1.4-2

COMPOSITE COOLING TOWER DRIFT EMISSION SPECTRUM[a]

Interval	d_l (μm)	d_u (μm)	Mass Fraction (%)
1	0	10	0.00
2	10	20	0.53
3	20	30	4.43
4	30	40	7.41
5	40	50	6.51
6	50	60	5.48
7	60	70	3.51
8	70	90	3.26
9	90	110	1.78
10	110	130	0.95
11	130	150	0.76
12	150	180	1.10
13	180	210	1.17
14	210	240	1.32
15	240	270	1.41
16	270	300	1.82
17	300	350	2.67
18	350	400	2.33
19	400	450	2.29
20	450	500	1.51
21	500	600	4.33
22	600	700	3.51
23	700	800	3.82
24	800	900	2.73
25	900	1000	1.71
26	1000	1200	3.19
27	1200	1400	3.32
28	1400	1600	6.43
29	1600	1800	2.21
30	1800	2000	3.07
31	2000	2200	15.4

a - Source: EPRI, 1984.
b - Droplet diameter lower (d_l) and upper (d_u) size range in microns (um) for given interval.

ground. Since terrain around the plant site is essentially flat, visibility on nearby roads is not expected to be degraded by the formation of this elevated visible plume.

Table 5.1.4-3 shows the frequency of elevated, visible plume formation and its length as a function of wind direction. The frequency of visible plume formation in all directions reduces to about 2 percent on an annual basis at 600 meters (0.38 mile) downwind of the tower. With respect to potential visibility impacts to air traffic, the nearest private airport is located 2.5 miles north of the plant site. At that distance, the visible plume is not expected to hinder the safe operation of aircraft during take-off or landing.

Induced ground-level fogging will occur during plume downwash conditions. However, this locally induced fog will be dissipated rapidly due to the high winds associated with such plume downwash conditions. Table 5.1.4-4 shows that most of the ground-level fogging exists within 300 meters of the plant. The south and south-southeast are the two directions for which plume fogging persists up to a distance of 1.25 kilometers for about an hour per year. Since the northwest-southeast oriented Route 710 is more than 750 meters to the northeast of the cooling tower, induced ground fog will not obstruct the traffic flow on Route 710.

Icing Potential

The SACTI model predicted no occurrence of induced icing in this subtropical area (see Table 5.1.4-4). Therefore, no icing potential exists as a direct result of cooling tower operations.

Salt Deposition Impacts on Soils

Seasonal and annual salt deposition rates were calculated out to a distance of 10 km downwind of the cooling tower. Annual salt deposition rates are presented in Table 5.1.4-5 in terms of kg/km^2-mo. These deposition rates can be converted

TABLE 5.1.4-3

VISIBLE PLUME FREQUENCY
Sheet 1 of 2

1 ************************************ PLUME LENGTH FREQUENCY TABLE ************************************

INDIANTOWN, 1982-86 WEST PALM BEACH MET. DATA (LMDCT, 10 CYCLES)

SEASON=ANNUAL

DISTANCE	WIND FROM																
FROM	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	SUM
TOWER	PLUME HEADED																
(M)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	SUM
50.	5.30	2.44	4.80	7.74	15.68	9.62	10.42	6.05	8.35	3.53	3.95	3.23	5.09	3.76	5.10	4.93	100.00
100.	.34	1.75	3.62	.81	1.02	.30	.39	.16	.22	2.17	2.57	.17	.40	.37	.40	.33	15.02
150.	.12	.44	.53	.77	.98	.13	.18	.13	.09	1.69	1.96	.05	.18	.30	.29	.05	7.89
200.	.02	.37	.41	.01	.04	.13	.18	.00	.00	1.51	1.79	.00	.00	.30	.29	.01	5.08
250.	.02	.25	.25	.01	.04	.13	.18	.00	.00	1.15	1.41	.00	.00	.30	.29	.01	4.05
300.	.00	.21	.19	.00	.00	.03	.03	.00	.00	.99	1.21	.00	.00	.20	.24	.00	3.10
350.	.00	.17	.15	.00	.00	.03	.03	.00	.00	.82	1.02	.00	.00	.20	.24	.00	2.67
400.	.00	.17	.15	.00	.00	.03	.03	.00	.00	.82	1.02	.00	.00	.20	.24	.00	2.67
450.	.00	.17	.15	.00	.00	.03	.03	.00	.00	.82	1.02	.00	.00	.20	.24	.00	2.67
500.	.00	.13	.12	.00	.00	.03	.03	.00	.00	.62	.73	.00	.00	.20	.24	.00	2.11
550.	.00	.13	.12	.00	.00	.03	.03	.00	.00	.62	.73	.00	.00	.20	.24	.00	2.11
600.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
650.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
700.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
750.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
800.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
850.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
900.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
950.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1000.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1050.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1100.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1150.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1200.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1250.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1300.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1350.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1400.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1450.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1500.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1550.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1600.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1650.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1700.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1750.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1800.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1850.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1900.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
1950.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2000.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2050.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2100.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2150.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2200.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2250.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2300.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2350.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2400.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2450.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2500.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08

TABLE 5.1.4-3

VISIBLE PLUME FREQUENCY
Sheet 2 of 2

1 ************************************ PLUME LENGTH FREQUENCY TABLE ************************************

INDIANTOWN, 1982-86 WEST PALM BEACH MET. DATA (LMDCT, 10 CYCLES)

SEASON=ANNUAL

DISTANCE FROM TOWER (M)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	SUM
(PLUME HEADED)	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	SUM
2550.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2600.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2650.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2700.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2750.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2800.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2850.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2900.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
2950.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3000.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3050.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3100.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3150.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3200.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3250.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3300.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3350.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3400.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3450.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3500.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3550.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3600.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3650.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3700.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3750.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3800.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3850.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3900.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
3950.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4000.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4050.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4100.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4150.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4200.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4250.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4300.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4350.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4400.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4450.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4500.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4550.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4600.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4650.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4700.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4750.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4800.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4850.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4900.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
4950.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08
5000.	.00	.13	.12	.00	.00	.03	.02	.00	.00	.62	.73	.00	.00	.18	.24	.00	2.08

Source: Bechtel, 1990

TABLE 5.1.4-4

FOGGING AND ICING FREQUENCIES

1 ************************************* HOURS OF PLUME FOGGING TABLE *************************************

INDIANTOWN, 1982-86 WEST PALM BEACH MET. DATA (LMDCT)

SEASON=ANNUAL

DISTANCE FROM TOWER (M)	WIND FROM																
	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	AVG
	PLUME HEADED																
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	AVG
100.	4.7	6.7	8.4	10.2	14.9	.0	.0	.9	.9	.8	1.5	.8	1.3	.0	.0	.9	51.9
150.	7.5	2.6	5.7	23.5	37.8	8.5	.5	2.5	2.5	.5	.4	.8	3.0	.8	.5	3.8	100.7
200.	7.1	.4	.8	16.9	34.8	1.9	.1	2.1	2.1	.1	.0	.2	3.0	.2	.1	2.4	72.3
250.	6.3	.0	.0	13.0	29.4	.0	.0	1.7	1.7	.0	.0	.0	2.6	.0	.0	2.0	56.7
300.	3.8	.0	.0	5.5	12.5	.0	.0	.7	.7	.0	.0	.0	1.1	.0	.0	2.0	26.4
350.	2.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	2.0	4.0
400.	2.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	2.0	4.0
450.	2.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	2.0	4.0
500.	2.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	2.0	4.0
600.	1.5	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.5	3.0
750.	1.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.0	2.0
1000.	1.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.0	2.0
1250.	.7	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.7	1.5
1500.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1750.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
2000.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0

1 ************************************* HOURS OF RIME ICING TABLE *************************************

INDIANTOWN, 1982-86 WEST PALM BEACH MET. DATA (LMDCT)

SEASON=ANNUAL

DISTANCE FROM TOWER (M)	WIND FROM																
	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	AVG
	PLUME HEADED																
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	AVG
100.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
150.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
200.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
250.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
300.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
350.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
400.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
450.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
500.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
600.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
750.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1000.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1250.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1500.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1750.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
2000.	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0

Source: Bechtel, 1990

TABLE 5.1.4-5

COOLING TOWER SALT DEPOSITION
Sheet 1 of 2

1 ************************************ PLUME SALT DEPOSITION TABLE (KG./(KM.**2-MO.)) ************************************

INDIANTOWN, 1982-86 WEST PALM BEACH MET. DATA (LMDCT, 10 CYCLES)

SEASON=ANNUAL

DISTANCE FROM TOWER (M)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	AVG
	WIND FROM																
	PLUME HEADED																
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	AVG
100.	14275.	9260.	20325.	29540.	58567.	32095.	33592.	19129.	22912.	8524.	9615.	8029.	12659.	9890.	13048.	11616.	19567.
200.	1220.	811.	1648.	2432.	4783.	2309.	2425.	1618.	2031.	1135.	1247.	709.	1132.	752.	989.	1024.	1642.
300.	355.	189.	368.	626.	1222.	641.	681.	424.	552.	306.	332.	210.	338.	212.	274.	317.	440.
400.	155.90	96.79	185.59	302.16	607.37	376.13	398.54	215.03	276.18	152.30	167.71	92.40	145.42	137.64	182.63	130.66	226.40
500.	112.58	44.19	84.58	150.72	307.94	187.54	205.79	132.92	197.61	72.64	80.82	70.61	111.35	48.03	62.36	106.76	123.53
600.	86.71	19.36	33.76	111.32	224.80	143.09	156.47	94.10	141.12	38.27	42.48	54.99	87.23	40.59	53.27	84.55	88.26
700.	40.49	14.31	25.33	68.80	137.59	111.68	121.19	50.23	67.68	24.14	27.51	23.41	36.79	32.73	41.81	34.50	53.64
800.	26.35	8.65	13.97	30.49	62.18	74.86	82.44	28.58	44.64	19.16	21.46	16.12	26.15	22.03	29.61	25.87	33.29
900.	17.79	5.45	8.69	21.67	42.54	46.63	53.01	16.99	24.76	11.74	13.02	9.95	16.54	18.80	25.19	16.77	21.85
1000.	15.45	3.94	6.25	20.88	40.77	44.66	50.22	15.49	21.44	8.49	9.47	8.33	13.74	17.80	23.43	14.02	19.65
1100.	18.58	3.21	4.99	18.81	37.24	40.36	44.53	15.44	27.17	7.17	7.95	12.08	20.93	14.30	18.10	18.99	19.37
1200.	23.52	4.59	5.93	16.86	32.89	36.44	40.44	15.73	36.24	14.22	15.35	17.48	31.64	12.28	15.42	26.54	21.60
1300.	10.34	3.75	4.78	12.42	24.36	26.30	29.60	9.37	14.34	11.93	12.80	5.62	9.62	7.83	10.04	10.25	12.71
1400.	21.07	1.63	2.84	20.06	47.09	18.41	19.82	30.39	41.71	2.80	3.24	11.69	17.61	3.89	5.52	13.51	16.3[illegible]
1500.	14.12	1.48	2.68	15.65	35.62	18.36	19.75	21.52	28.55	2.47	2.82	7.66	11.43	3.87	5.50	8.51	12.50
1600.	3.34	.80	1.23	6.08	11.61	16.80	18.23	3.60	4.72	2.03	2.30	1.80	3.04	3.65	5.28	3.16	5.48
1700.	3.31	.51	.61	5.86	11.34	13.06	14.11	3.56	4.70	1.79	2.03	1.79	2.99	3.26	4.78	3.15	4.80
1800.	3.20	.49	.60	5.82	11.28	5.31	5.66	3.49	4.58	1.74	1.95	1.75	2.93	2.72	3.93	3.06	3.66
1900.	3.17	.48	.58	5.80	11.26	5.18	5.49	3.48	4.56	1.69	1.87	1.74	2.91	2.47	3.45	3.03	3.57
2000.	3.16	.46	.56	5.80	11.24	4.95	5.18	3.46	4.52	1.64	1.83	1.73	2.89	2.02	2.66	3.02	3.45
2100.	3.15	.41	.50	5.80	11.22	4.88	5.06	3.45	4.52	1.47	1.67	1.73	2.89	1.93	2.49	3.01	3.39
2200.	2.55	.37	.45	3.08	5.98	4.56	4.76	2.32	3.64	1.31	1.47	1.51	2.53	1.88	2.45	2.76	2.60
2300.	2.39	.34	.41	3.02	5.88	1.58	1.92	2.20	3.42	1.18	1.34	1.43	2.40	1.17	1.60	2.56	2.05
2400.	2.00	.29	.36	2.91	5.63	1.28	1.56	1.95	2.86	.94	1.09	1.18	2.00	.66	1.00	2.01	1.73
2500.	1.55	.26	.33	2.75	5.31	1.23	1.49	1.70	2.30	.80	.88	.85	1.43	.63	.97	1.38	1.49
2600.	1.27	.25	.32	2.68	5.17	1.05	1.25	1.59	2.01	.77	.83	.66	1.09	.59	.92	1.00	1.34
2700.	1.15	.23	.30	2.41	4.83	.76	.90	1.51	1.87	.74	.80	.57	.92	.46	.76	.87	1.19
2800.	1.10	.23	.30	2.40	4.80	.76	.90	1.48	1.79	.73	.80	.54	.86	.43	.73	.82	1.17
2900.	.95	.16	.21	2.34	4.63	.76	.90	1.36	1.51	.54	.62	.45	.69	.43	.73	.68	1.06
3000.	.73	.14	.19	1.63	3.18	.76	.89	.94	1.05	.47	.55	.34	.55	.43	.72	.57	.82
3100.	.40	.13	.17	.21	.44	.35	.46	.34	.58	.41	.49	.23	.37	.40	.68	.43	.38
3200.	.36	.12	.17	.19	.41	.33	.41	.31	.53	.39	.46	.21	.34	.38	.63	.39	.35
3300.	.34	.11	.15	.18	.40	.32	.40	.30	.52	.35	.40	.20	.33	.38	.62	.38	.34
3400.	.34	.11	.15	.18	.40	.32	.40	.30	.52	.35	.40	.20	.33	.38	.62	.38	.34
3500.	.34	.10	.13	.18	.40	.32	.40	.30	.52	.28	.35	.20	.33	.38	.62	.38	.33
3600.	.34	.09	.12	.18	.40	.32	.40	.30	.52	.21	.27	.20	.33	.38	.62	.38	.32
3700.	.34	.08	.10	.18	.40	.32	.40	.30	.52	.20	.26	.20	.33	.38	.62	.38	.31
3800.	.34	.04	.05	.18	.40	.32	.40	.30	.52	.11	.15	.20	.33	.38	.62	.38	.30
3900.	.34	.03	.04	.18	.40	.27	.32	.30	.52	.06	.07	.20	.33	.29	.46	.38	.26
4000.	.32	.02	.04	.16	.37	.24	.28	.28	.50	.06	.07	.20	.32	.23	.33	.36	.23
4100.	.30	.02	.04	.14	.34	.23	.27	.26	.48	.06	.07	.20	.31	.19	.28	.35	.22
4200.	.30	.02	.04	.14	.34	.22	.26	.26	.47	.06	.06	.19	.31	.19	.27	.35	.22
4300.	.30	.02	.03	.14	.34	.21	.24	.26	.47	.06	.06	.19	.31	.17	.25	.35	.21
4400.	.30	.02	.03	.14	.34	.17	.18	.26	.47	.05	.06	.19	.31	.13	.17	.35	.20
4500.	.24	.02	.03	.09	.21	.17	.18	.16	.34	.05	.06	.16	.26	.12	.17	.32	.16
4600.	.24	.02	.03	.09	.20	.16	.17	.16	.33	.05	.06	.16	.26	.12	.16	.32	.16
4700.	.24	.02	.03	.09	.20	.16	.17	.15	.32	.05	.06	.16	.25	.12	.16	.31	.16
4800.	.24	.02	.03	.09	.20	.16	.17	.15	.32	.05	.05	.16	.25	.12	.16	.31	.15
4900.	.24	.02	.03	.09	.20	.16	.17	.15	.32	.05	.05	.16	.25	.12	.16	.31	.15
5000.	.20	.02	.03	.08	.17	.16	.17	.13	.27	.05	.05	.13	.20	.12	.16	.25	.14

TABLE 5.1.4-5

COOLING TOWER SALT DEPOSITION
Sheet 2 of 2

1 ************************************ PLUME SALT DEPOSITION TABLE (KG./(KM.**2-MO.)) ************************************
INDIANTOWN, 1982-86 WEST PALM BEACH MET. DATA (LMDCT, 10 CYCLES)
SEASON=ANNUAL

DISTANCE FROM TOWER (M)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	AVG
	******** WIND FROM ********																
	******** PLUME HEADED ********																
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	AVG
5100.	.20	.02	.03	.08	.17	.16	.17	.13	.27	.05	.05	.13	.20	.12	.16	.25	.14
5200.	.20	.02	.03	.08	.17	.16	.17	.13	.27	.05	.05	.13	.20	.12	.16	.25	.14
5300.	.19	.02	.02	.08	.17	.16	.17	.12	.25	.05	.05	.12	.19	.12	.16	.24	.13
5400.	.17	.02	.02	.07	.16	.16	.17	.10	.23	.05	.05	.11	.18	.12	.16	.21	.12
5500.	.16	.02	.02	.07	.15	.16	.17	.10	.22	.05	.05	.11	.17	.12	.16	.20	.12
5600.	.13	.02	.02	.06	.14	.16	.17	.09	.18	.05	.05	.08	.14	.12	.16	.16	.11
5700.	.12	.02	.02	.06	.13	.16	.17	.09	.18	.05	.05	.08	.13	.12	.16	.14	.10
5800.	.10	.02	.02	.06	.12	.16	.17	.08	.15	.05	.05	.07	.12	.12	.16	.12	.10
5900.	.09	.02	.02	.05	.12	.16	.16	.07	.14	.05	.05	.06	.11	.10	.14	.11	.09
6000.	.09	.02	.02	.05	.12	.15	.16	.07	.14	.05	.05	.06	.11	.09	.12	.11	.09
6100.	.09	.02	.02	.05	.12	.15	.16	.07	.14	.05	.05	.06	.11	.09	.12	.11	.09
6200.	.09	.02	.02	.05	.12	.15	.16	.07	.14	.05	.05	.06	.11	.09	.12	.11	.09
6300.	.09	.02	.02	.05	.12	.15	.16	.07	.14	.05	.05	.06	.11	.09	.12	.11	.09
6400.	.09	.02	.02	.05	.12	.15	.16	.07	.14	.05	.05	.06	.11	.09	.11	.11	.09
6500.	.09	.02	.02	.05	.11	.15	.16	.07	.14	.05	.05	.06	.11	.08	.11	.11	.09
6600.	.09	.02	.02	.05	.11	.14	.15	.07	.14	.05	.05	.06	.11	.07	.09	.10	.08
6700.	.09	.02	.02	.05	.11	.14	.15	.07	.14	.05	.05	.06	.11	.07	.09	.10	.08
6800.	.09	.02	.02	.05	.11	.14	.15	.07	.14	.05	.05	.06	.11	.07	.09	.10	.08
6900.	.09	.02	.02	.05	.11	.14	.15	.07	.14	.04	.05	.06	.11	.07	.09	.10	.08
7000.	.09	.02	.02	.05	.11	.14	.15	.07	.14	.04	.05	.06	.11	.07	.09	.10	.08
7100.	.09	.02	.02	.05	.11	.14	.15	.07	.14	.04	.05	.06	.11	.07	.09	.10	.08
7200.	.09	.02	.02	.05	.11	.14	.15	.07	.14	.04	.05	.06	.11	.07	.09	.10	.08
7300.	.09	.02	.02	.05	.11	.14	.15	.07	.14	.04	.05	.06	.11	.07	.09	.10	.08
7400.	.08	.02	.02	.05	.11	.14	.15	.06	.13	.04	.05	.06	.10	.07	.09	.09	.08
7500.	.07	.02	.02	.05	.11	.14	.15	.06	.12	.04	.05	.06	.09	.07	.10	.08	.08
7600.	.07	.02	.02	.05	.11	.14	.15	.06	.12	.04	.05	.06	.09	.07	.10	.08	.08
7700.	.07	.02	.02	.05	.11	.14	.15	.06	.12	.04	.05	.06	.09	.07	.10	.08	.08
7800.	.07	.02	.02	.05	.11	.14	.15	.06	.12	.04	.05	.06	.09	.07	.10	.08	.08
7900.	.07	.02	.02	.05	.11	.14	.15	.06	.12	.04	.05	.06	.09	.07	.10	.08	.08
8000.	.07	.02	.02	.05	.11	.14	.15	.06	.12	.04	.05	.06	.09	.07	.10	.08	.08
8100.	.07	.02	.02	.05	.11	.14	.15	.06	.12	.04	.05	.06	.09	.07	.10	.08	.08
8200.	.07	.02	.02	.05	.11	.14	.15	.06	.12	.04	.04	.05	.09	.07	.10	.08	.08
8300.	.06	.02	.02	.05	.10	.14	.15	.05	.11	.04	.04	.05	.09	.07	.10	.08	.07
8400.	.06	.02	.02	.05	.10	.14	.15	.05	.11	.04	.04	.05	.09	.07	.09	.08	.07
8500.	.06	.02	.02	.05	.10	.14	.15	.05	.11	.04	.04	.05	.09	.07	.09	.08	.07
8600.	.06	.02	.02	.05	.10	.14	.15	.05	.11	.04	.04	.05	.09	.07	.09	.08	.07
8700.	.06	.02	.02	.05	.10	.14	.14	.05	.11	.04	.04	.05	.09	.07	.09	.08	.07
8800.	.06	.02	.02	.05	.10	.14	.14	.05	.11	.04	.04	.05	.08	.06	.09	.07	.07
8900.	.06	.01	.02	.04	.10	.14	.14	.05	.10	.04	.04	.04	.07	.06	.08	.07	.07
9000.	.05	.01	.02	.04	.08	.13	.14	.04	.08	.03	.04	.04	.07	.06	.07	.06	.06
9100.	.05	.01	.02	.04	.08	.13	.13	.04	.08	.03	.04	.04	.07	.04	.05	.06	.06
9200.	.05	.01	.02	.04	.08	.13	.13	.04	.08	.03	.04	.04	.07	.04	.05	.06	.06
9300.	.05	.01	.02	.04	.07	.13	.13	.03	.07	.03	.03	.03	.05	.04	.05	.05	.05
9400.	.04	.01	.02	.03	.07	.11	.11	.03	.06	.03	.03	.03	.05	.04	.05	.05	.05
9500.	.04	.01	.02	.03	.07	.10	.10	.03	.06	.03	.03	.03	.05	.04	.05	.05	.05
9600.	.04	.01	.02	.03	.07	.10	.10	.03	.06	.03	.03	.03	.05	.04	.05	.05	.05
9700.	.04	.01	.02	.03	.07	.10	.10	.03	.06	.03	.03	.03	.05	.04	.05	.05	.05
9800.	.04	.01	.02	.03	.07	.10	.10	.03	.06	.03	.03	.03	.05	.04	.05	.05	.05
9900.	.04	.01	.02	.03	.07	.10	.10	.03	.06	.03	.03	.03	.05	.04	.05	.05	.05
10000.	.04	.01	.02	.03	.07	.10	.10	.03	.06	.03	.03	.03	.05	.04	.05	.05	.05

Source: Bechtel, 1990

to units of lb/acre-mo by applying a multiplication factor of 0.0089. As shown in Table 5.1.4-5, most of the drift is deposited onsite within 100 meters of the cooling tower.

The maximum annual average offsite salt deposition rate is 18.1 lbs/acre-mo. This value occurred 200 m north of the tower on the property of the Caulkins Citrus processing facility. At 500 meters north of the cooling tower, the maximum deposition rate reduces to 1.8 lbs/acre-mo. At this same downwind distance, the minimum salt deposition rate of 0.4 lb/acre-mo occurred south-southwest of the tower.

One mechanism for the impact of saline drift on plants is through the absorption of salt accumulated in the soil. Accumulation will occur if the annual deposition of salt exceeds the rate at which salt is washed from the soil by rainfall. The results of studies (MPPSP, 1979, pp. 4-18 to 4-23) with sandy loam soil suggest that a deposition rate of about 89 lbs/acre-mo (100 kg/Ha-mo) of NaCl can cause some accumulation of salt in the soil. As stated above, the maximum annual average offsite salt deposition rate is 18.1 lbs/acre-mo. During the summer months, the SACTI model predicts a higher maximum deposition rate of 24.7 lbs/acre-mo. Since these values are lower than the monthly threshold value that could cause salt accumulation in soil, no significant soil impacts are expected.

Salt Deposition Impacts on Vegetation

An investigation of the potential effects of cooling tower drift on vegetation was conducted in which predicted salt deposition rates were compared to available known salt injury thresholds. A predicted salt deposition rate is presented as the amount of salt deposited over a unit area per season and year at a certain direction and "distance" away from the tower.

Near the proposed power plant site boundary, salt deposition rates on an annual basis range from 0.42 to 216.9 lbs/acre-year. These are obtained by multiplying the predicted monthly deposition rates by 12. The greatest concentrations are located to the north and east of the proposed power plant, where existing industrial facilities are located.

A cautionary limit of 100 pounds of salt per acre-year can be used for agricultural areas based upon known salt injury thresholds to other crops (e.g., tobacco, 214 lbs/acre-year; corn, 107 lbs/acre-year; and soybean, 107-154 lbs/acre-year), (Mulchi, Wolf, and Armbruster, 1978).

Citrus, a potentially sensitive plant to salt deposition, is present in large groves from the south-southeast clockwise through the southwest, and to the northwest of the cooling tower. The closest groves are about 4,000 feet to the southwest and about 4,200 feet to the south of the cooling tower. At these locations, the highest levels of salt deposition over an annual period are about 0.6 lb/acre-yr and 1.1 lbs/acre-yr, respectively; which should not result in any significant foliar, shoot, or fruit damage or any long-term reductions in growth, yield, or photosynthesis.

Cooling tower drift will also deposit salt on the improved pasture, truck crops, dairy farms, and sugar cane agricultural land in the area around the proposed plant site, but at greater distances from the tower than the citrus groves. The agricultural land around the proposed plant should not be affected by these emissions, since the maximum amount of salt deposited will only amount to about 1 lb/acre-year at the closest distance of agricultural activities near the site (i.e., the citrus groves). That is, the proposed plant operation should not cause the cautionary limit for agriculture to be approached or exceeded within agricultural areas.

Based upon a literature review, one of the most sensitive native plant species to salt injury is flowering dogwood (Cornus florida). The lowest injury threshold for flowering dogwood is reported at 81 lbs/acre-year (Curtis, et al., 1978). Although flowering dogwood is only naturally occurring much further north of Martin County, a similar dogwood species, stiff cornell (Cornus foemina) would be expected within the mixed and cypress swamps in the immediate area (approximately 2,900 feet southeast of the cooling tower). On the basis of the reported injury threshold and a predicted maximum annual salt deposition rate of 2.7 lbs/acre-year in the vicinity of forested wetlands offsite, no adverse effects to dogwood or other indigenous vegetation is expected offsite.

Native vegetation associated with pine and wet prairies occurs onsite and along the property boundaries. Salt deposition could, at a maximum, range from 172.8 to 216.9 lbs of salt per acre-year on the northern property boundaries, and at higher rates within the site. Such high levels could result in plant injury. However, the "units" of the modeling result in Table 5.1.4-5 imply that the deposition rate value applies over an area, a square-kilometer, for example. The value that is determined for each receptor point is calculated assuming that the rate of deposition is the same over the unit area. As the values in Table 5.1.4-5 show, close to the cooling tower there is a large gradient in deposition values between adjacent wind direction sectors and successive 100-meter increments of downwind distances which can only occur if the deposition rate varies significantly over the unit area. Therefore, the deposition rates for these close-in receptor points must be used with caution in evaluating potential effects on plants as they could greatly overestimate impacts.

Based upon the assumption that ambient salt deposition rates in the region are minimal, incremental salt deposited from the cooling towers should have no significant adverse effect on natural vegetation or crops just outside site boundaries or in the region of the proposed plant site.

5.1.5 MEASUREMENT PROGRAM

This section is not applicable since there will not be a heated effluent discharged to a receiving body of water. Ambient air quality monitoring is discussed in Section 5.6.2.

5.2 EFFECTS OF CHEMICAL AND BIOCIDE DISCHARGES

5.2.1 INDUSTRIAL WASTEWATER DISCHARGES

When using the primary source of water, Taylor Creek/Nubbin Slough (TC/NS), for process water makeup, wastewater from the plant (excluding cooling tower blowdown) is reused to meet the spray dryer lime slurry dilution water demand. When using the backup sources of water for process water makeup (mixture of TC/NS water from the cooling water storage pond and groundwater from the upper production zone of the upper Floridan aquifer), the majority of the wastewater from the plant (excluding cooling tower blowdown) is reused to meet the spray dryer lime slurry dilution water demand. The remainder is mixed with brine from the reverse osmosis unit and cooling tower blowdown and sent to the injection well. Table 5.2.1-1 summarizes the wastewater flows (both process wastewater and cooling tower blowdown) from the ICL plant.

Section 3.6.2 discusses the wastewater treatment scheme to control pH, oil, and suspended solids. Section 3.5.1.5 addresses the discharge of the wastewater into the Boulder Zone of the Floridan aquifer via the injection wells. There is no wastewater discharge from the plant to a surface receiving body of water.

Table 5.2.1-2 presents the quality of the wastewater discharged via the injection well for two cases: average annual flows using the primary source of water and maximum daily flows using the backup sources of water.

No hazardous materials may be discharged via the injection well. Therefore, the measures described in Section 3.5.1.5 will be taken to ensure that any hazardous solvents, degreasers, or other chemicals that may be used at the plant will not enter the floor drains or equipment drains connected to the wastewater equalization tank.

Table 5.2.1-1
SUMMARY OF WASTEWATER DISCHARGES FROM THE ICL PROJECT

Case:	Maximum Daily (MGD)	Maximum Monthly (MG/Mo)	Average Annual (MGY)
Primary Source of Water			
Plant Wastewater	0.215	6.57	77.5
Cooling Tower Blowdown	0.446	13.0	145
Reuse as Spray Dryer Dilution	-0.235	-7.28	-85.7
TOTAL TO INJECTION WELL	0.426	12.3	137
Backup Sources of Water			
Plant Wastewater	0.444	13.5	40.4
Cooling Tower Blowdown	1.63	46.7	135
Reuse as Spray Dryer Dilution	-0.235	-7.28	-21.8
TOTAL TO INJECTION WELL	1.84	52.9	154

Notes:

1. Wastewater from the ICL plant is discharged to the Boulder Zone of the lower Floridan aquifer via an injection well.
2. Maximum daily discharge flows are based on design flows through the cooling tower and 100 percent load factor for 24 hours.
3. Maximum monthly discharge flows are based on the highest average monthly flows through the cooling tower at 100 percent load factor for 31 days.
4. Average annual wastewater discharge flows when using the primary source of water are based on the annual average flows through the cooling tower at 100 percent load factor for 365 days. Average annual wastewater discharge flows when using the backup source of water are based on the annual average flows through the cooling tower at 100 percent load factor for 3 months.

Source: Bechtel, 1990

Table 5.2.1-2
SUMMARY OF THE ICL WASTEWATER QUALITY

Parameter	Primary Water Source (mg/l)	Backup Water Source (mg/l)
pH	6-9	6-9
Total Dissolved Solids	3,240	14,800
Total Hardness (as $CaCO_3$)	364	1,560
Oil/Grease	<15	<15
Residual Chlorine	<1.0	<1.0
Alkalinity (as $CaCO_3$)	153	118
Silica	25	17
Calcium	103	285
Magnesium	26	207
Sodium	994	4,820
Potassium	61	96
Iron	0.73	<0.06
Sulfate	1,095	1,480
Chloride	832	7,700
Fluoride	-	3.2
Nitrate	0.69	-
Phosphate	0.68	<2.3

NOTES:

1. Concentrations are in mg/l of the ion.
2. The wastewater effluent quality for the primary water source (Taylor Creek/Nubbin Slough) is based on average annual flows through the water and wastewater treatment system. These flows are based on the average annual meteorological conditions for the cooling tower, 100 percent load factor and 24 hours per day for 365 days. The cooling tower operates at 10 cycles of concentration.
3. The wastewater effluent quality for the backup water source (lower production zone of the upper Floridan aquifer for cooling water makeup and mixture of Taylor Creek/Nubbin Slough and upper production zone of upper Floridan aquifer for process water makeup) is based on maximum daily flows through the water and wastewater treatment system. These flows are based on design meteorological conditions for operation of the cooling tower and 100 percent load factor for 24 hours. The cooling tower operates at 3.5 cycles of concentration.

Source: Bechtel, 1990

The quality of the groundwater in the Boulder Zone of the Floridan aquifer (into which wastewater from the plant is being discharged) resembles that of seawater. A typical quality is shown in Table 5.2.1-3. The quality of the plant effluent will not degrade the quality of the groundwater in the Boulder Zone. There are no known users of groundwater from the Boulder Zone of the lower Floridan aquifer, either for industrial process water or for potable water. Therefore, there are no significant impacts due to the injection of wastewater from the ICL plant into the Boulder Zone of the lower Floridan aquifer.

Table 5.2.1-3
TYPICAL WATER QUALITY FOR LOWER FLORIDAN BOULDER ZONE

Parameter	(mg/l)
pH (Lab)	7.4
Total Dissolved Solids	38,200
Total Hardness	6,470
Alkalinity	100
Calcium	2,800
Magnesium	3,670
Iron	0.76
Sulfate	2,680
Chloride	19,400
Fluoride	0.62

NOTE:

This analysis was of a sample taken from a 3,320-foot deep well approximately 24 miles from the ICL plant.

Source: CH2M Hill, 1990

5.2.2 COOLING TOWER BLOWDOWN

When using the primary source of water for cooling water makeup (Taylor Creek/Nubbin Slough), a portion of the cooling tower blowdown is reused to meet the spray dryer lime slurry dilution water demand. The remainder of the cooling tower blowdown is discharged to the Boulder Zone of the lower Floridan aquifer via the injection well. When using the backup source of water for cooling water makeup (lower production zone of the upper Floridan aquifer), all of the cooling tower blowdown is discharged to the Boulder Zone of the lower Floridan aquifer. Table 5.2.1-1 summarizes the cooling tower blowdown flows from the plant under various operating conditions.

The chemicals used to treat the circulating water are described in Section 3.6.1.1. Section 5.2.1 addresses impacts due to the discharge of wastewater into the Boulder Zone of the Floridan aquifer via the injection wells.

5.2.3 MEASUREMENT PROGRAMS

The injection well monitoring plan is fully described in Section 3.5.1.5. This plan includes measuring wastewater quality and measuring water quality in the monitoring well to detect changes caused by possible migration of the injected wastewater.

5.3 IMPACTS ON WATER SUPPLIES

5.3.1 SURFACE WATER

This section discusses the effects of plant water withdrawal from the Taylor Creek/Nubbin Slough (TC/NS) on the C-59, L-63N, and L-63S Canals water levels, Lake Okeechobee, other users, and the groundwater level.

5.3.1.1 Plant Water Withdrawal

As discussed in Sections 3.5 and 10.9, the annual average plant water requirement is about 7.5 cfs and the historic average flow in the TC/NS is 146.4 cfs. Therefore, the annual average plant withdrawal from the canal is about 5 percent of the TC/NS flow, and the impact on the flow is minimal.

The predicted water levels in the TC/NS canals caused by the plant water withdrawal are discussed comprehensively in Section 10.9. Based on that analysis for the selected minimum design water level criteria of 16 feet-MSL, the predicted water levels in the canal will not deviate significantly from the historical levels at S-191 during a normal year. Figures 5.3.1-1 through 5.3.1-16 compare the predicted water levels against the historic ones. During the drought conditions, the canal water level may drop 2 to 3 feet below its historic water levels.

Depending on the drought frequency, the duration of low water levels may last from a few days to 60 consecutive days. The effect of the canal water level drop on the adjacent groundwater is discussed further in Section 5.3.1.3.

5.3.1.2 Lake Okeechobee

As discussed in Section 2.3.4.l, the mean annual discharge from S-191 into Lake Okeechobee amounts to about 106,000 acre-feet per year, which represents about

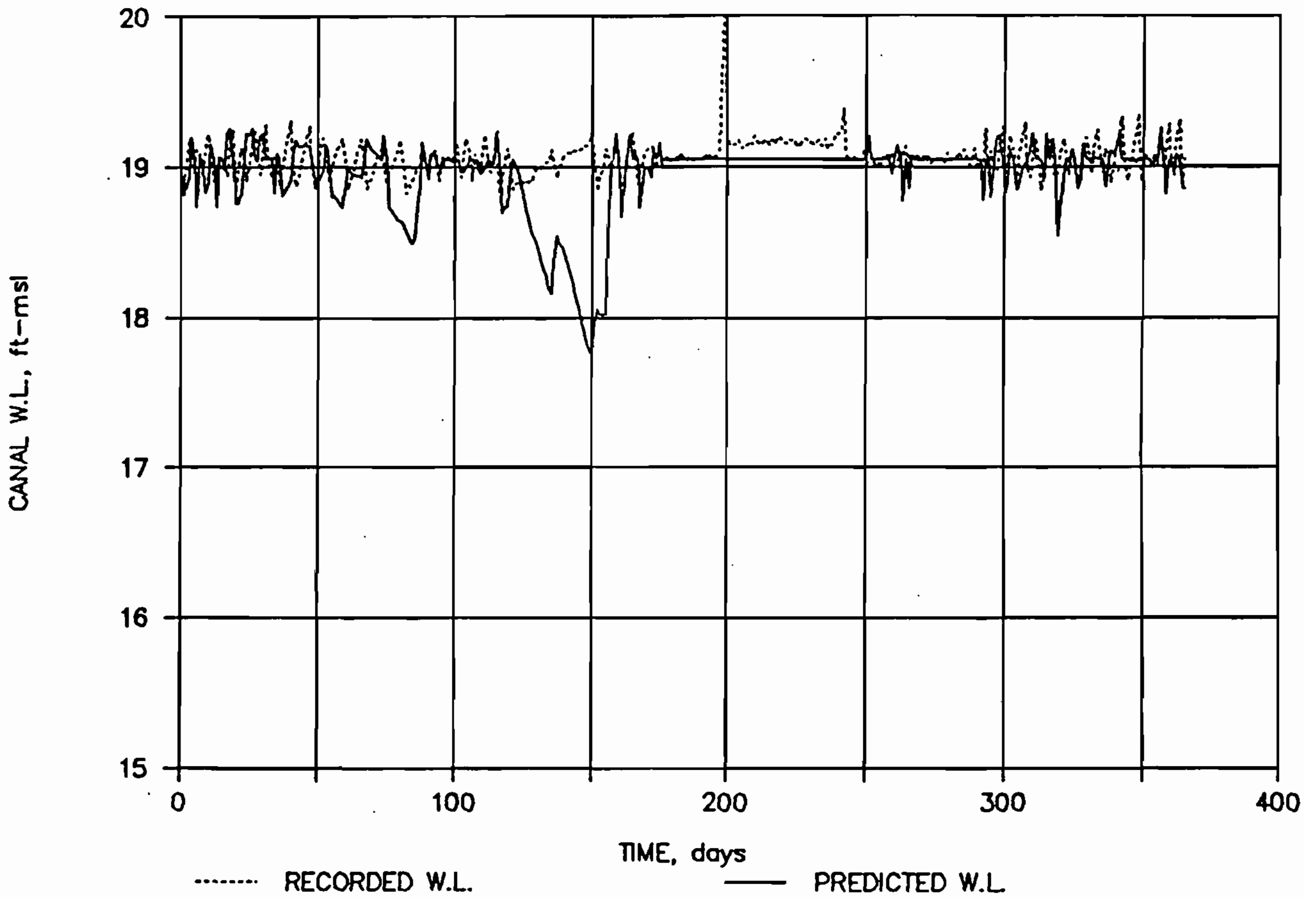

Figure 5.3.1-1.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1974

Source: Bechtel, 1990

INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

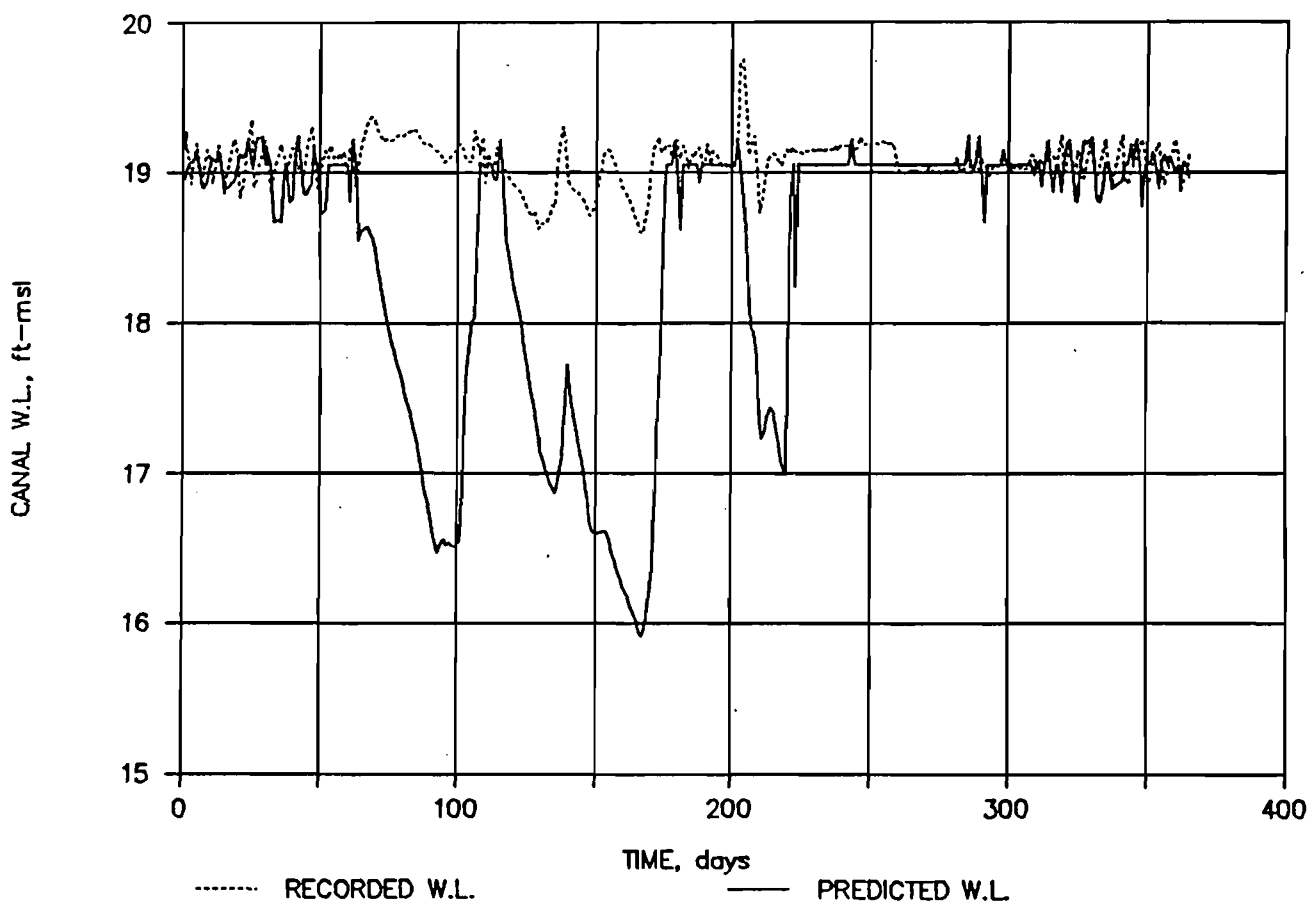

Figure 5.3.1-2.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1975

Source: Bechtel, 1990

INDIANTOWN
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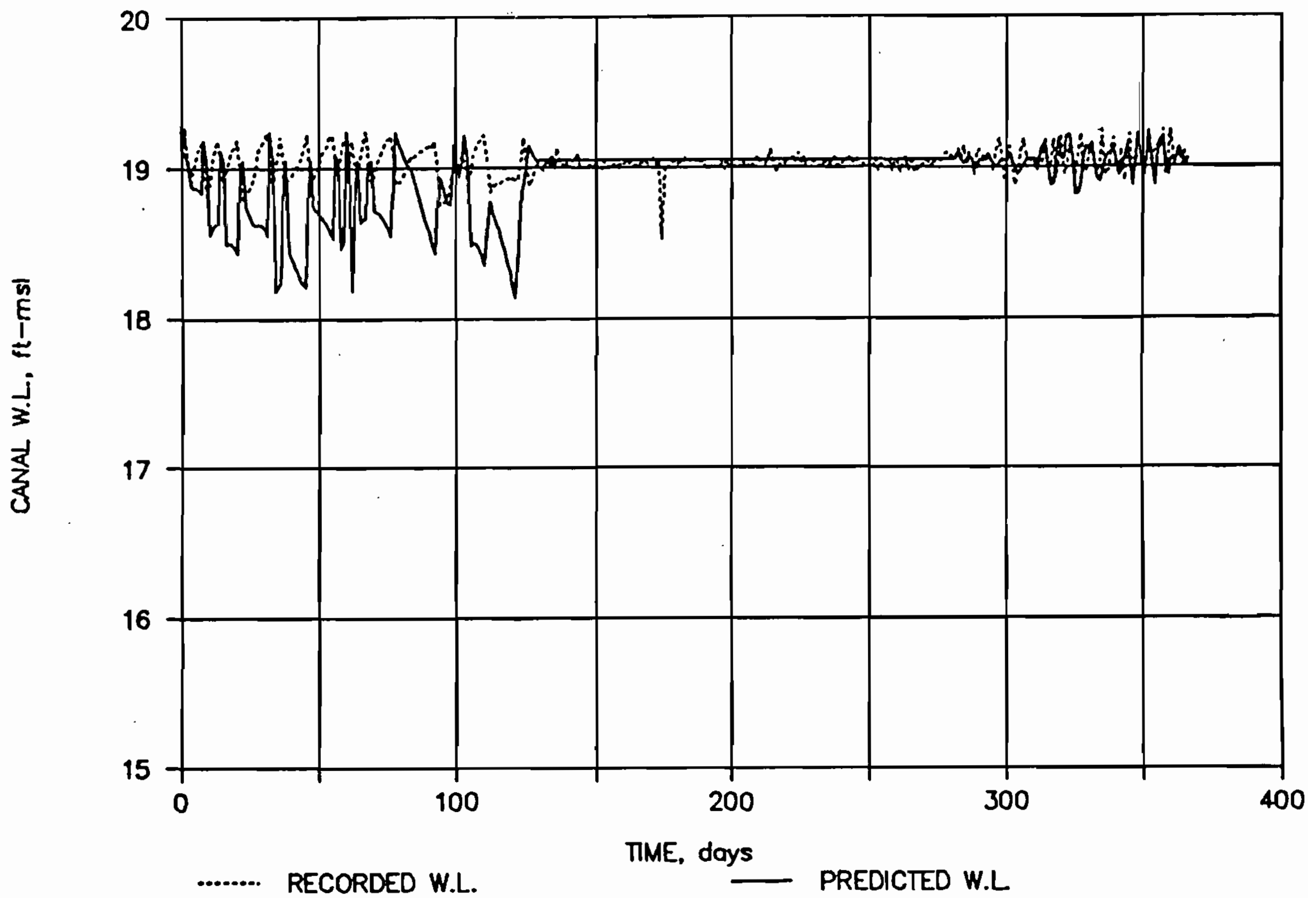

Figure 5.3.1-3.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1976

Source: Bechtel, 1990

INDIANTOWN
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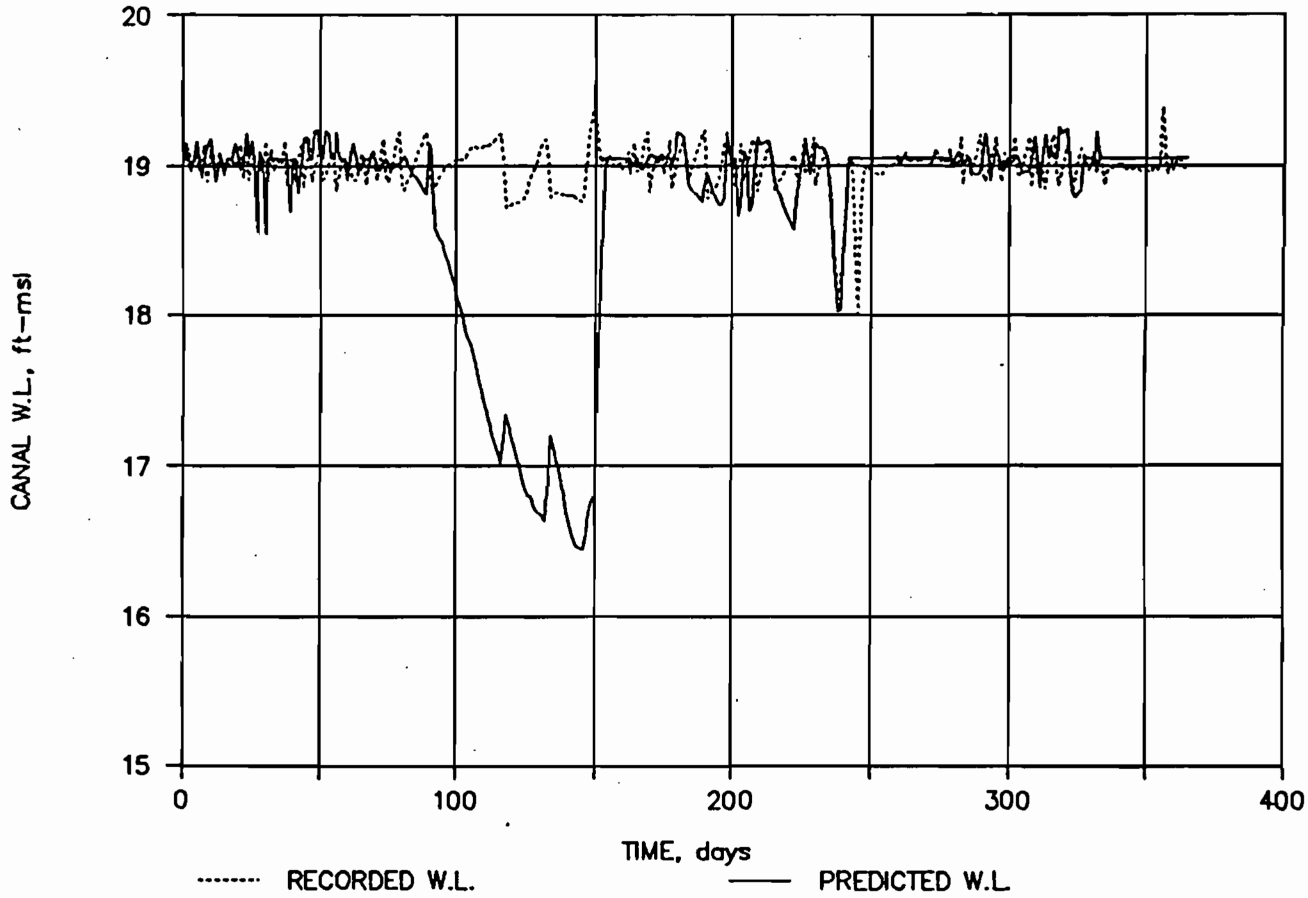

Figure 5.3.1-4.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1977

Source: Bechtel, 1990

INDIANTOWN
COGENERATION
PROJECT

Indiantown Cogeneration, L.P.

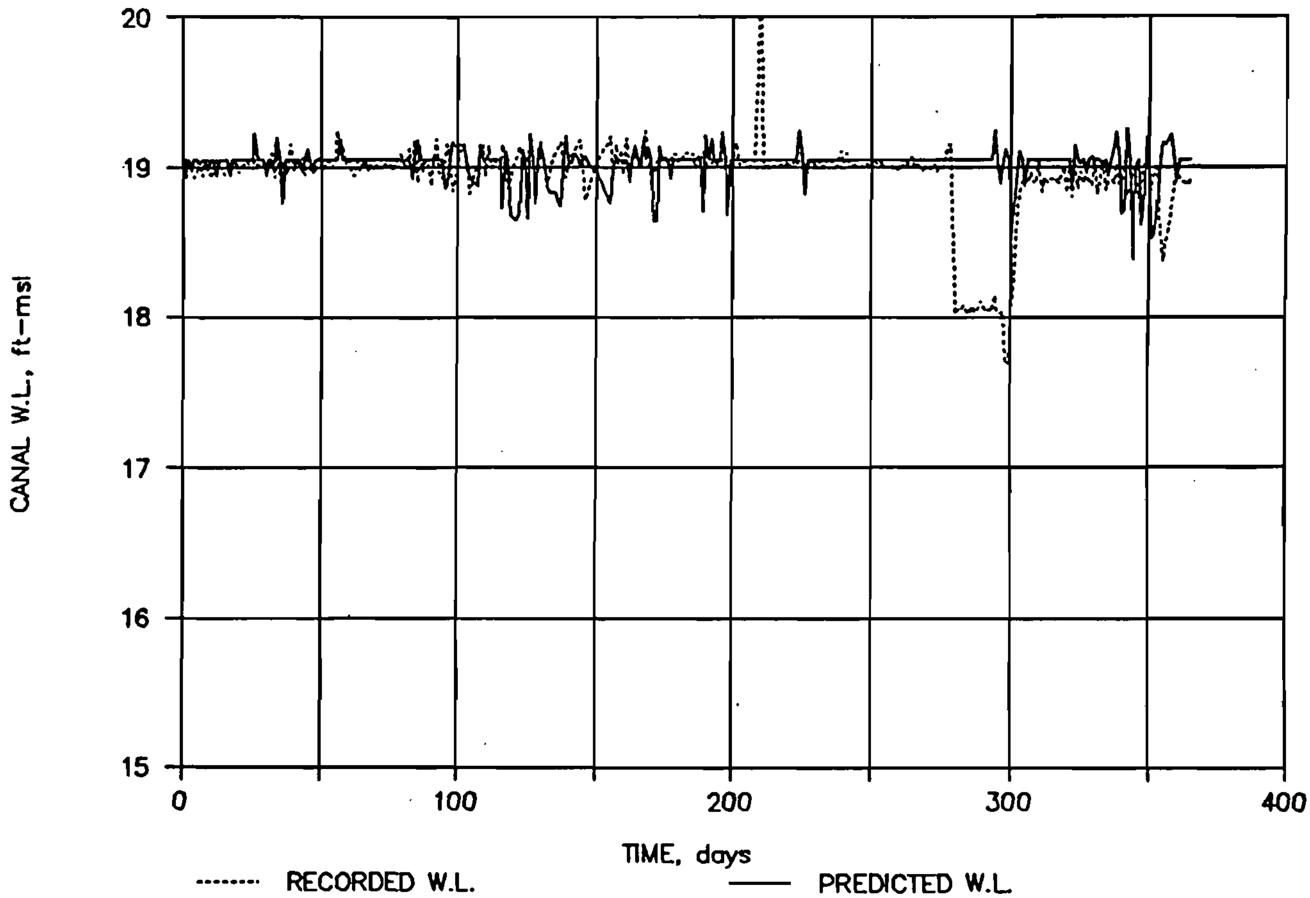

Figure 5.3.1-5.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1978

Source: Bechtel, 1990

INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

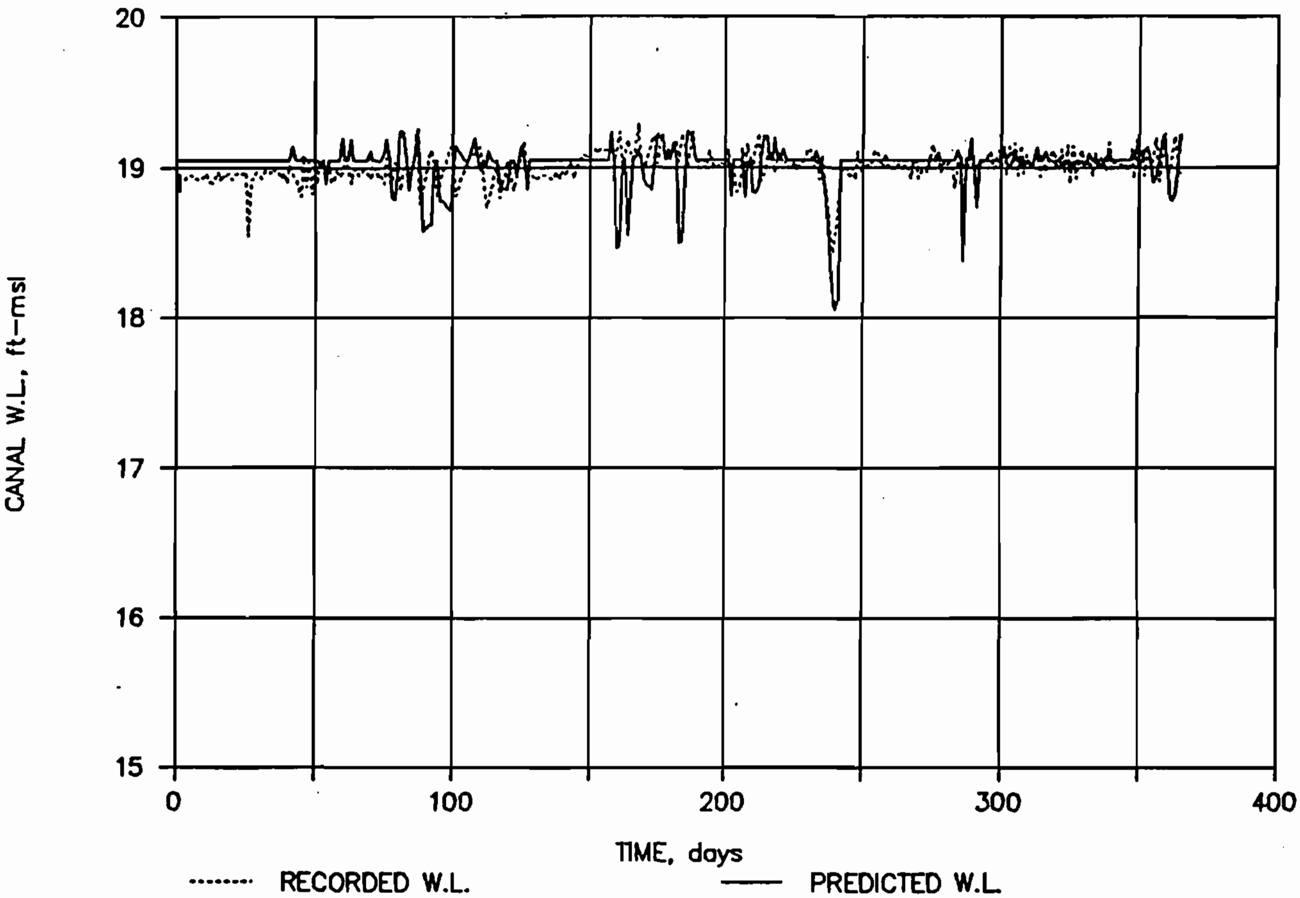

Figure 5.3.1-6.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1979

Source: Bechtel, 1990

INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

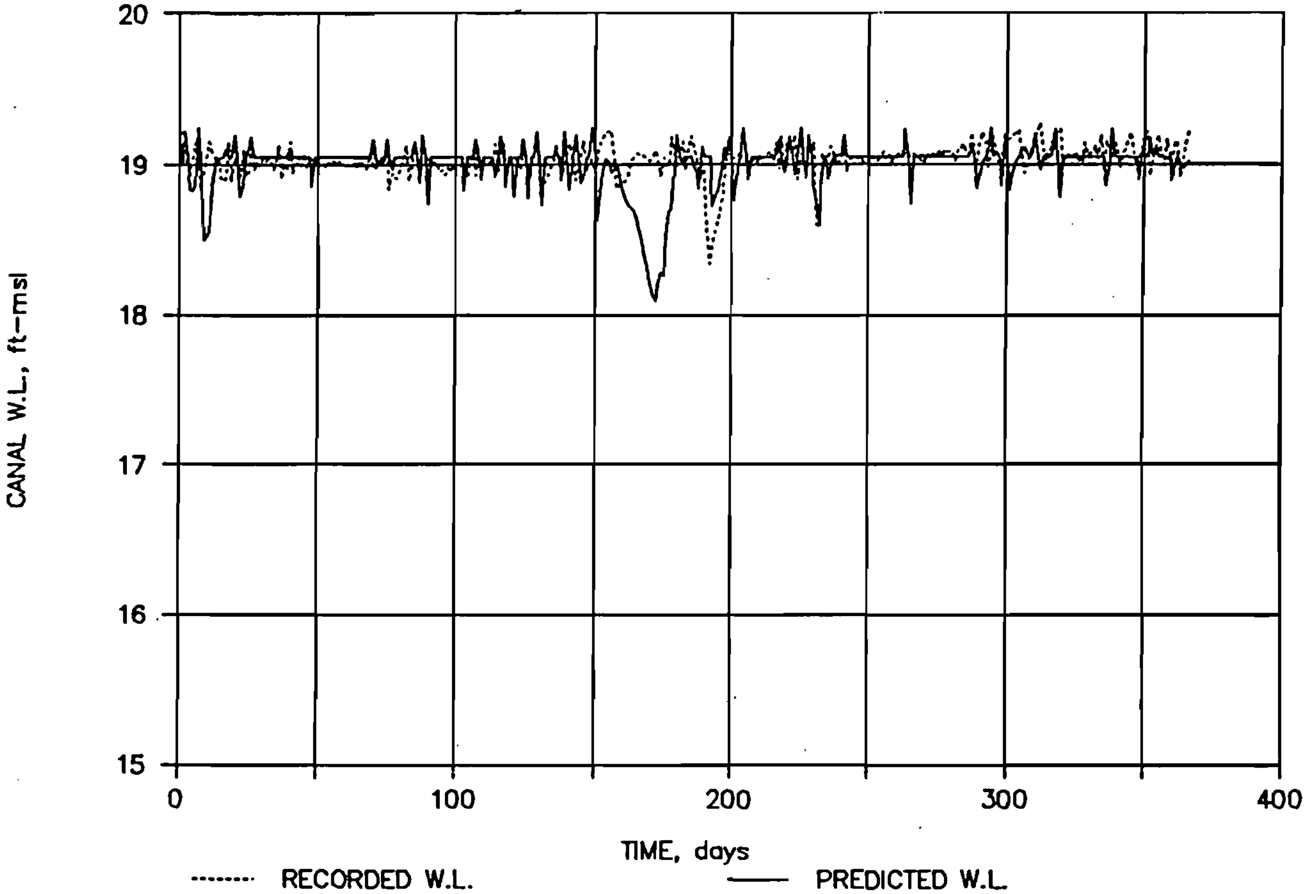

Figure 5.3.1-7.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1980

Source: Bechtel, 1990

INDIANTOWN
COGENERATION
PROJECT

Indiantown Cogeneration, L.P.

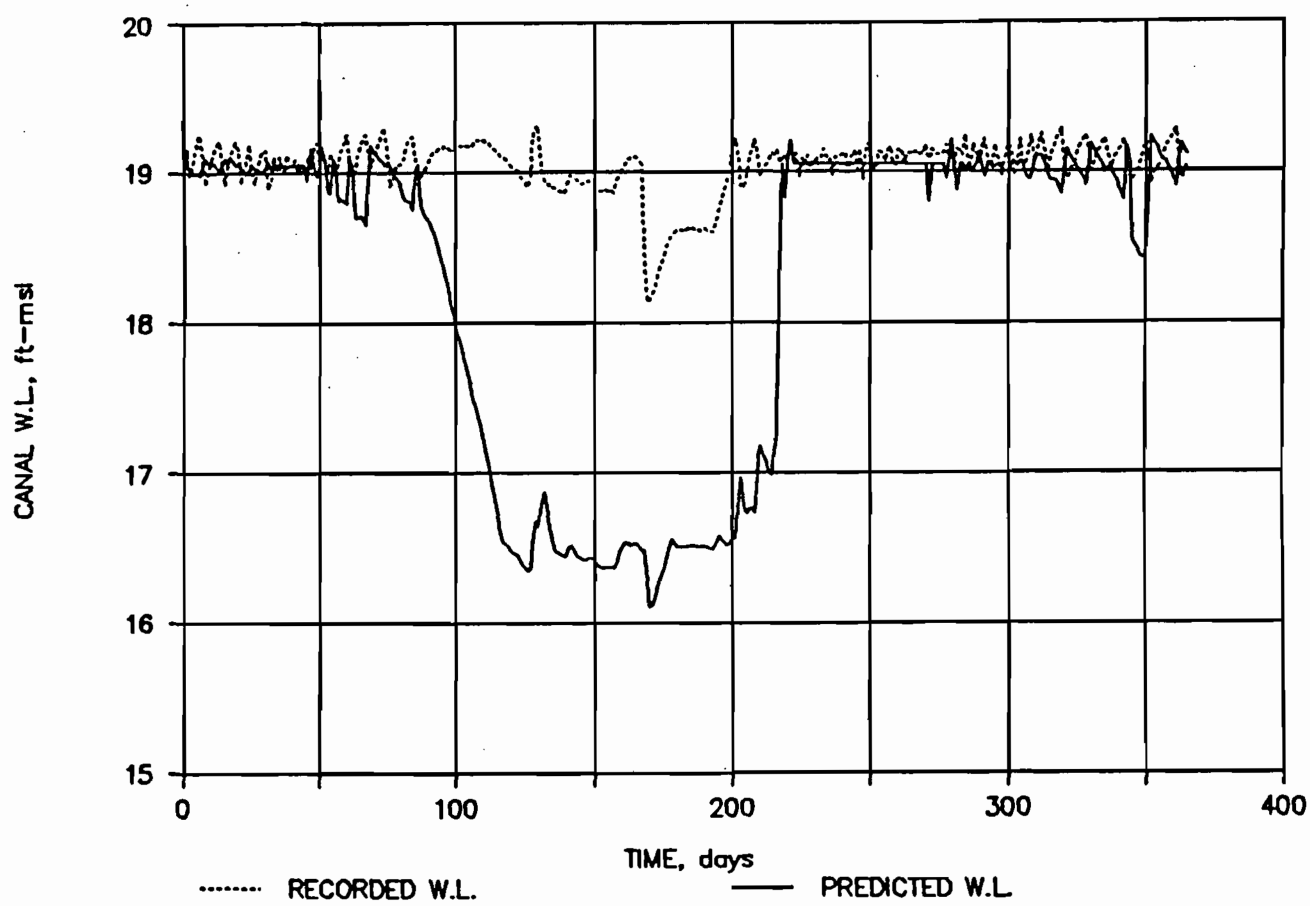

Figure 5.3.1-8.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1981

Source: Bechtel, 1990

INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

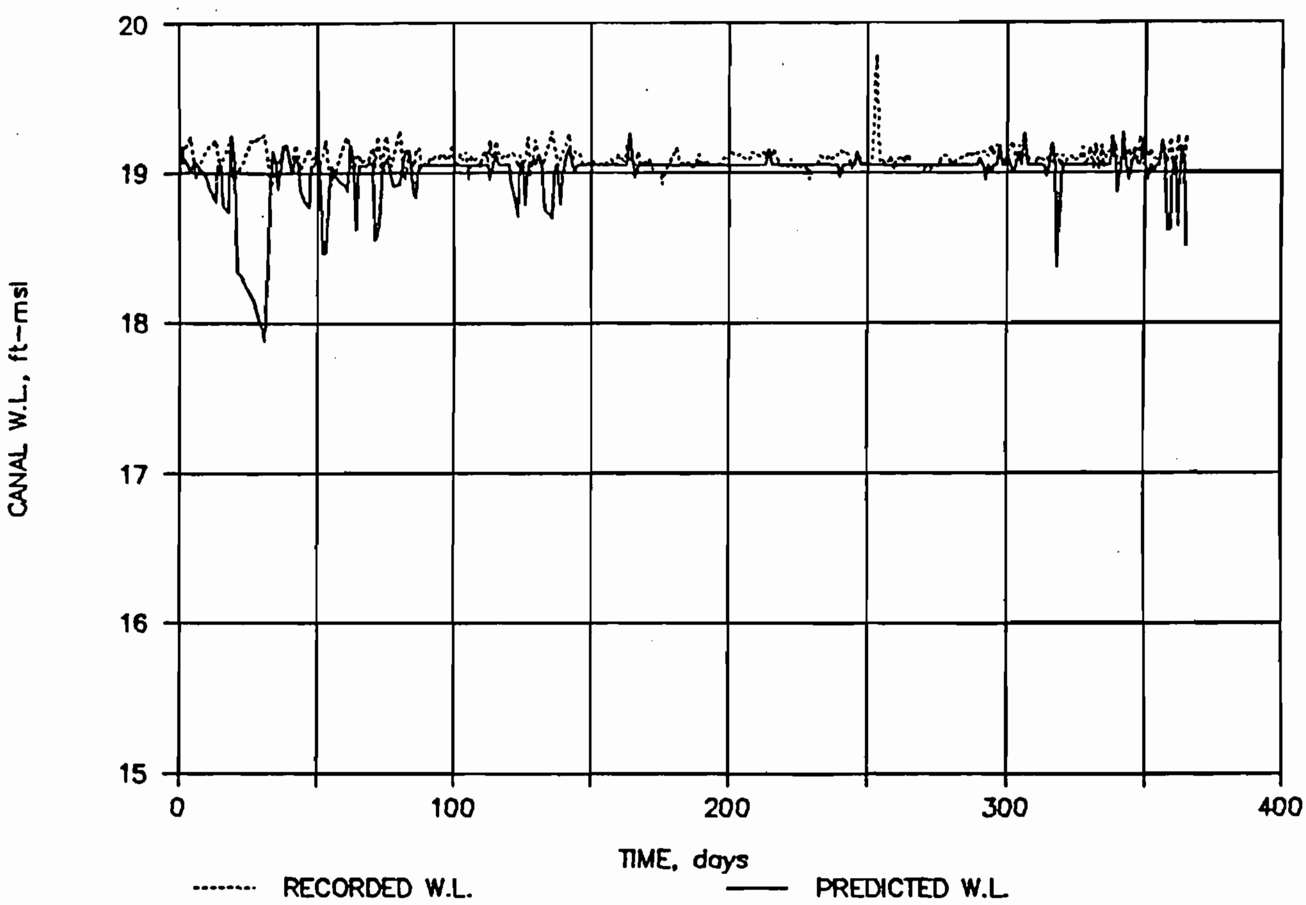

Figure 5.3.1-9.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1982

Source: Bechtel, 1990

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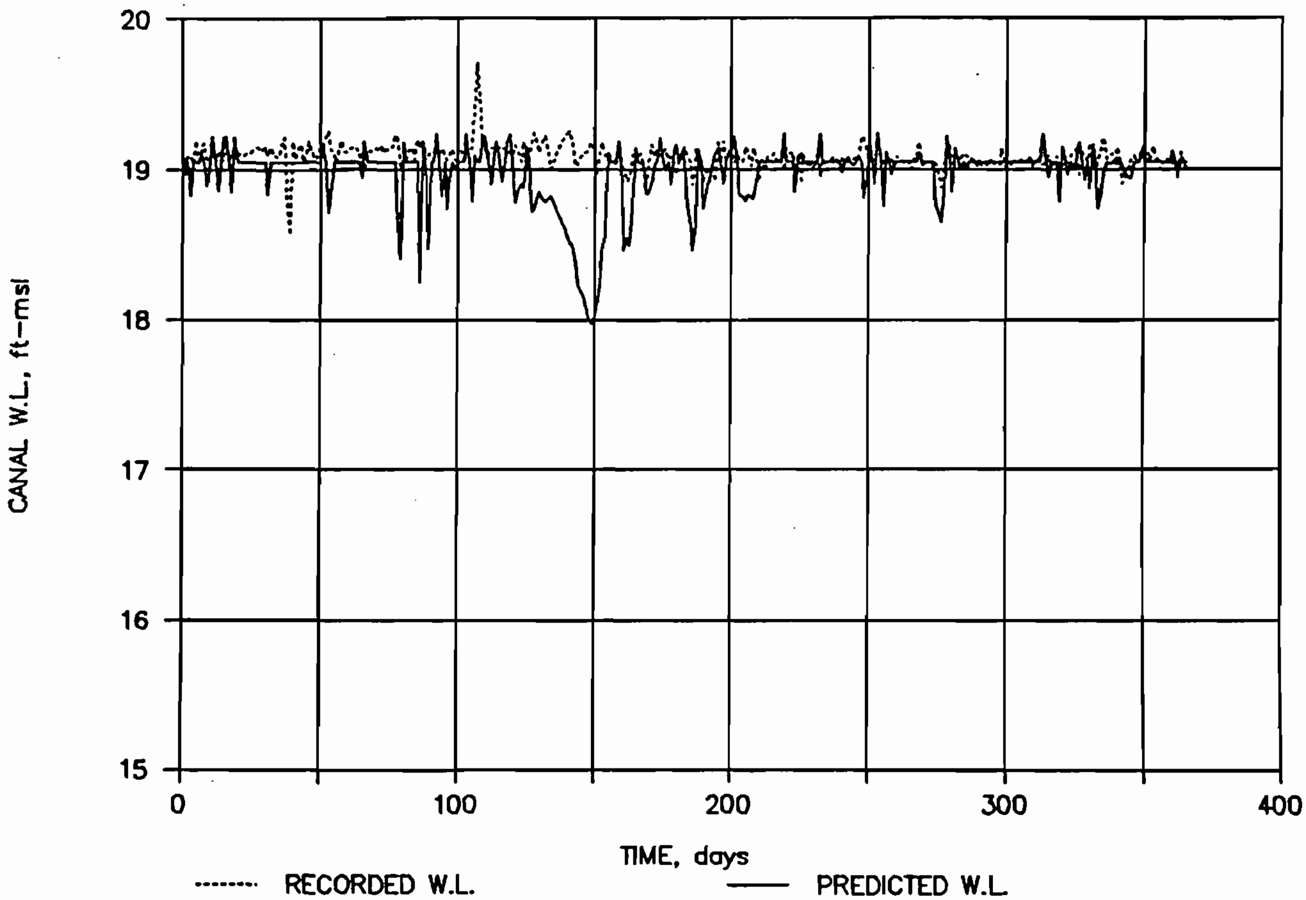

Figure 5.3.1-10.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1983

Source: Bechtel, 1990

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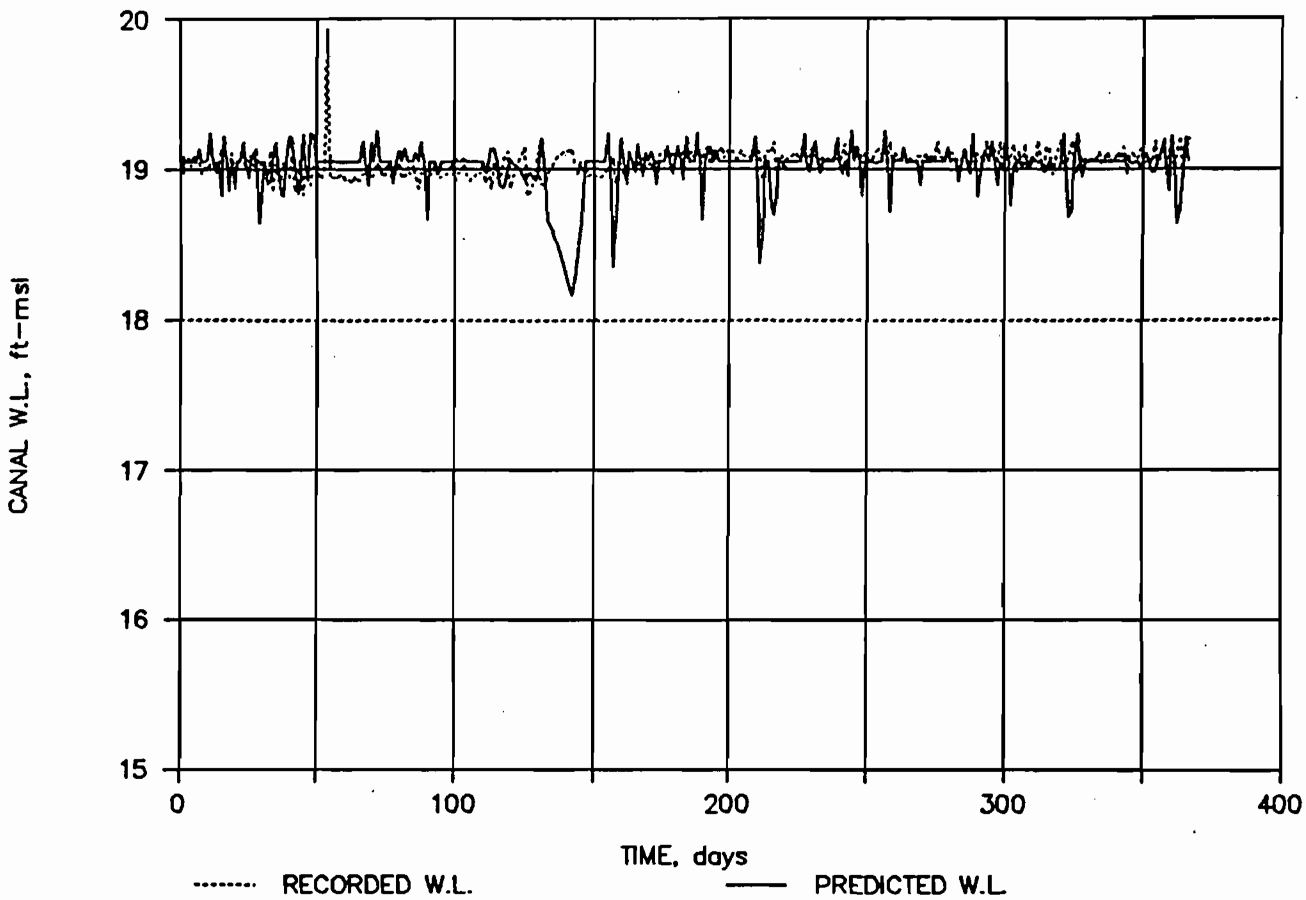

Figure 5.3.1-11.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1984

Source: Bechtel, 1990

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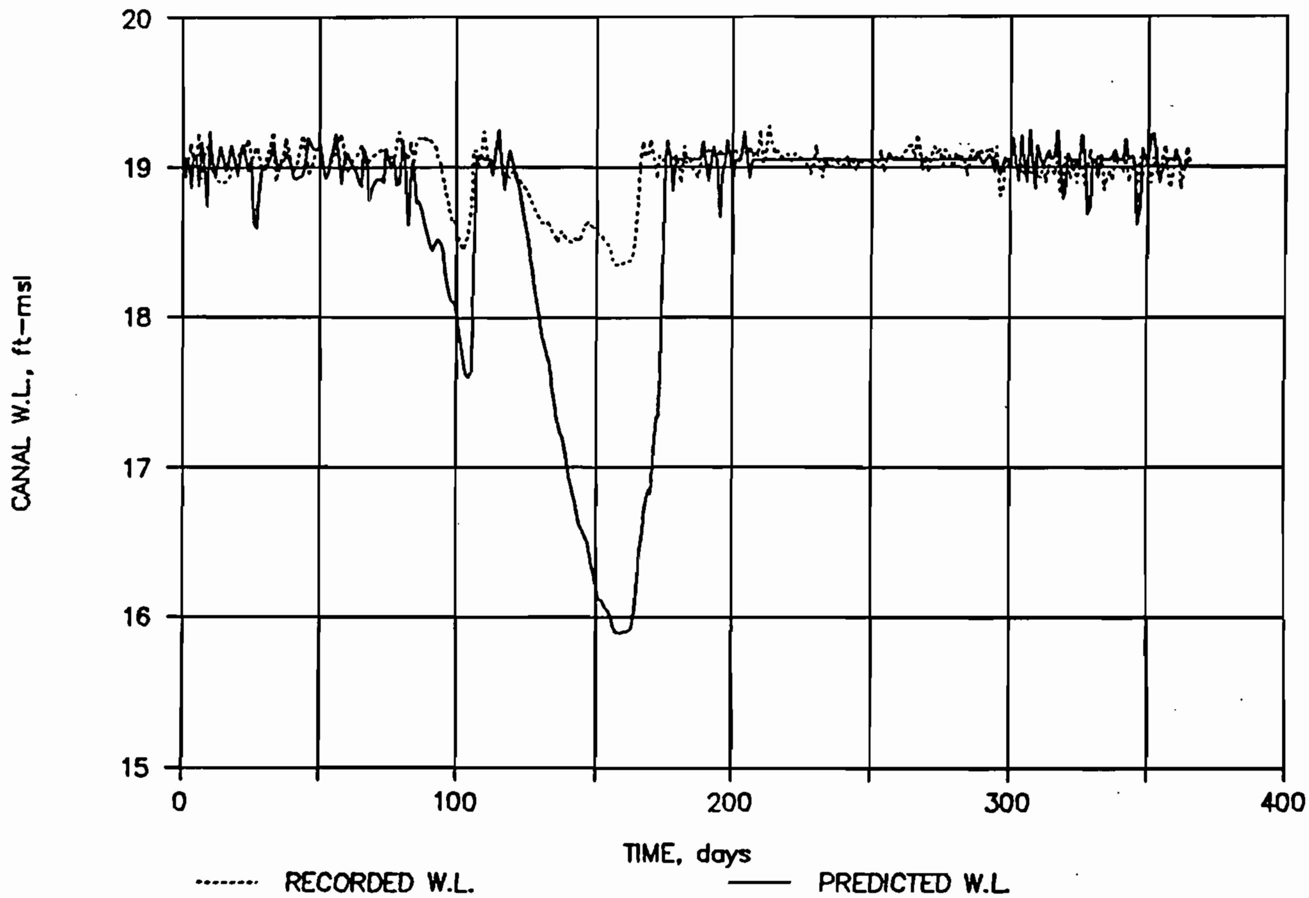

Figure 5.3.1-12.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1985

Source: Bechtel, 1990

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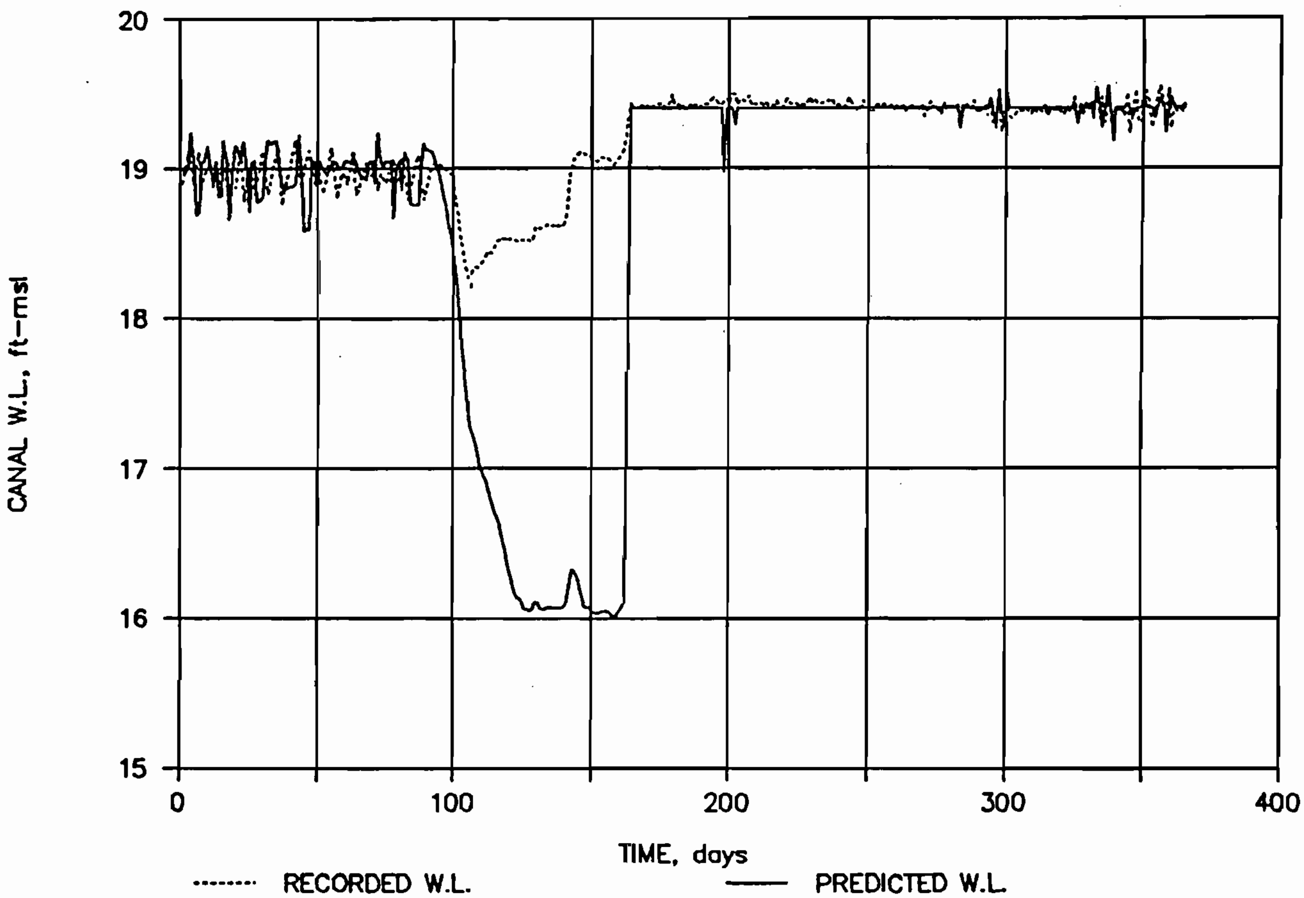

Figure 5.3.1-13.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1986

Source: Bechtel, 1990

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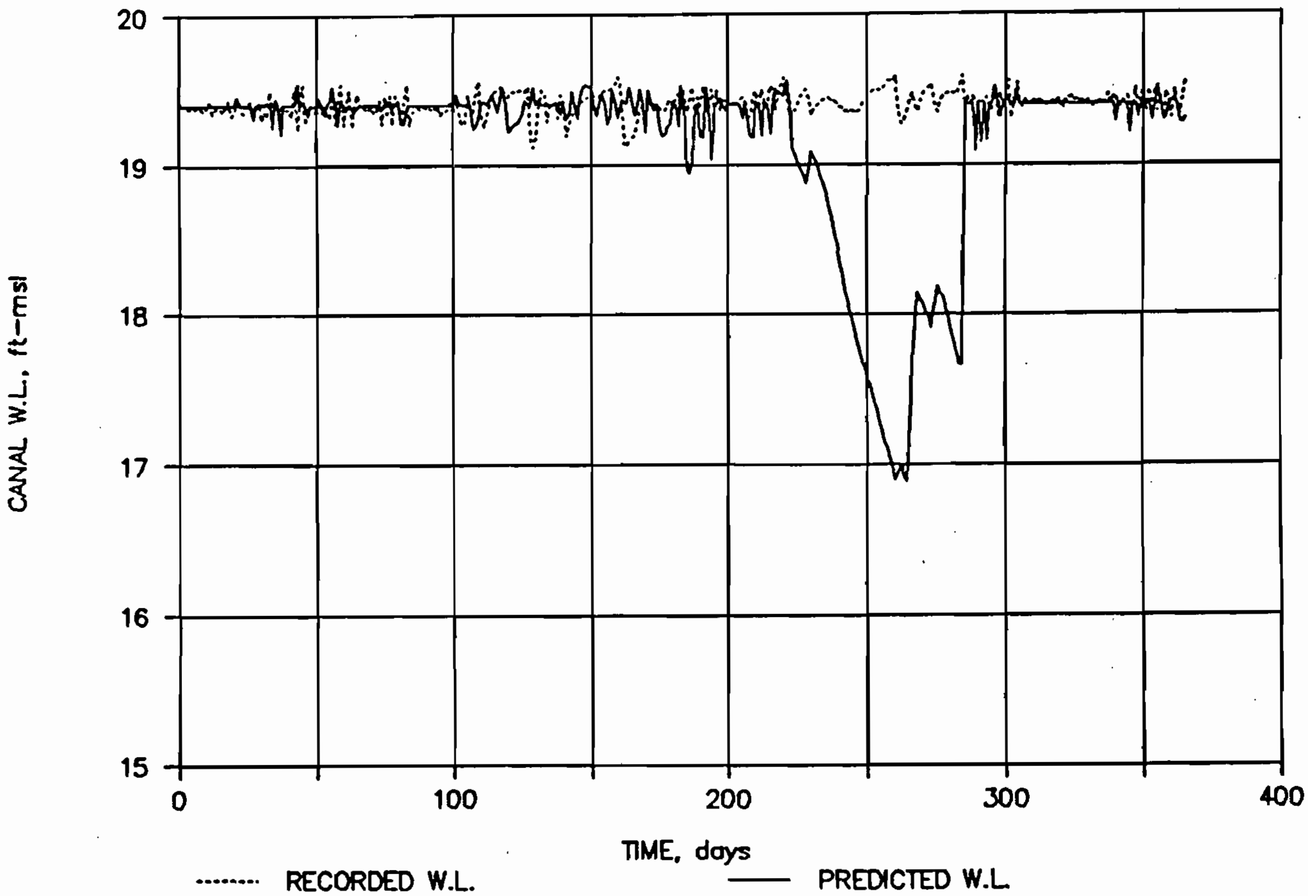

Figure 5.3.1-14.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1987

Source: Bechtel, 1990

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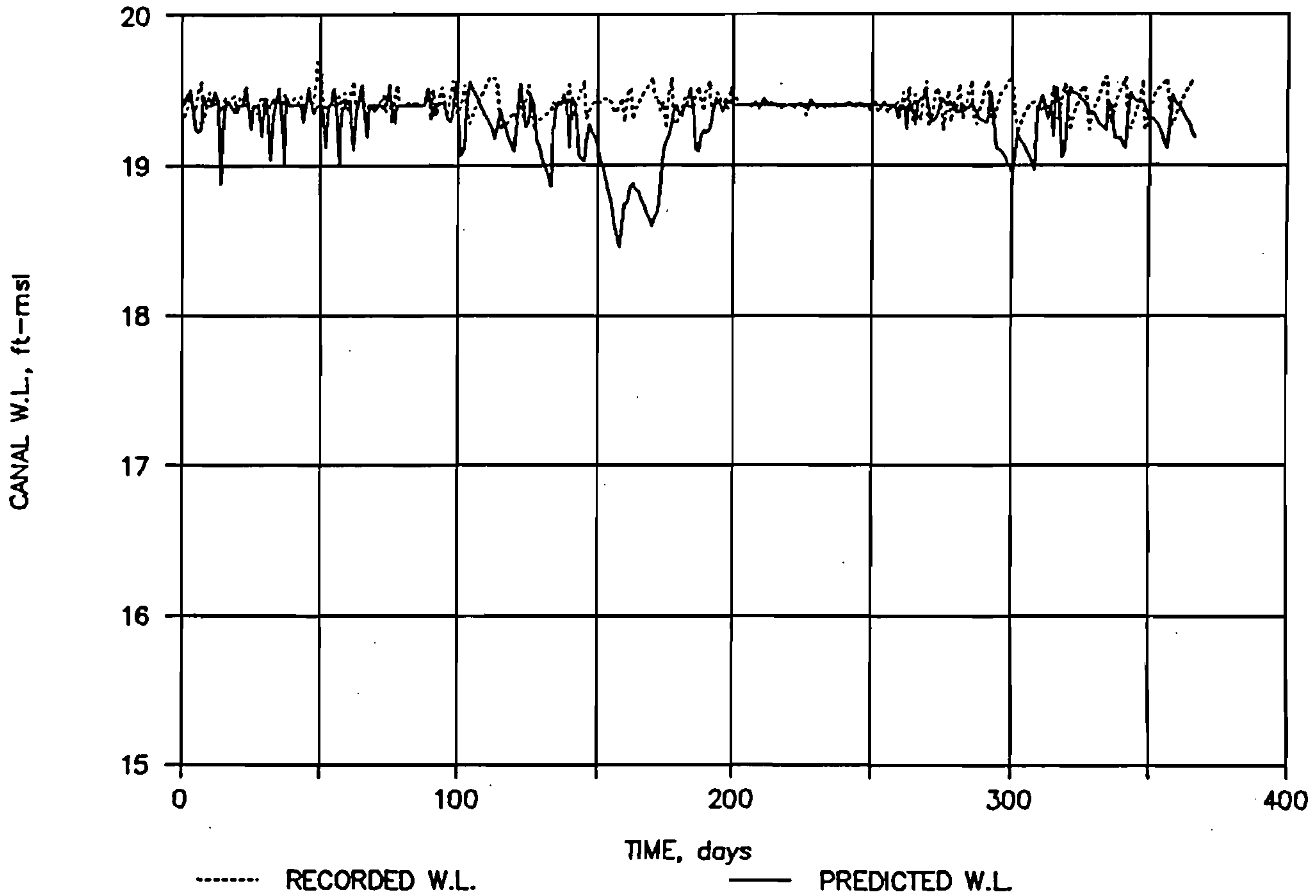

Figure 5.3.1-15.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1988

Source: Bechtel, 1990

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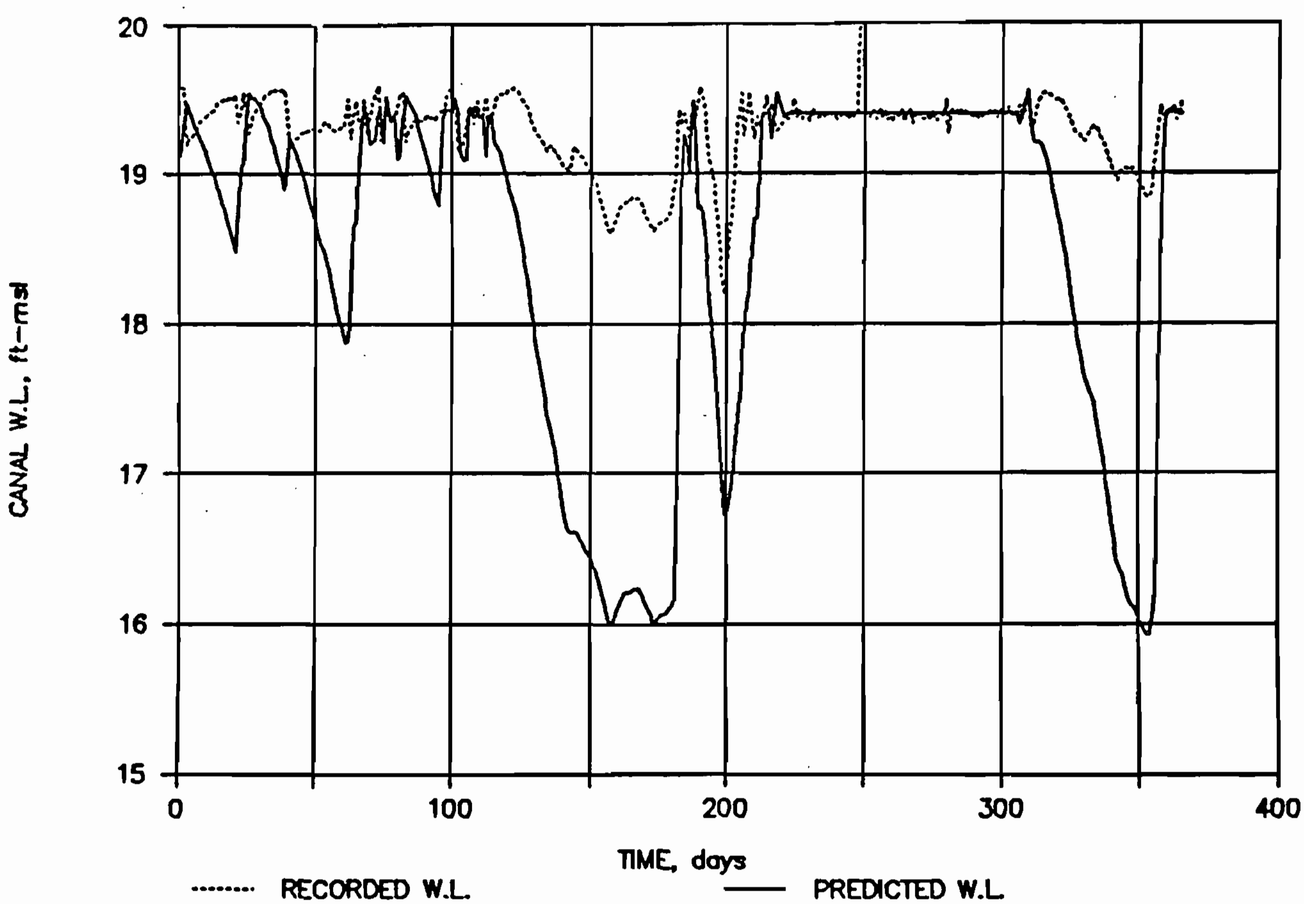

Figure 5.3.1-16.

MAKEUP AND PROCESS WATER WITHDRAWAL, 1989

Source: Bechtel, 1990

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3 percent of the total annual inflow to the lake of approximately 3,500,000 acre-feet. The plant annual water withdrawal from TC/NS is 5,430 acre-feet. The plant withdrawal will cause a reduction in the total annual inflow to the lake by 0.16 percent. The effect of such withdrawal on the lake's annual water budget is negligible.

However, relative to the impact on the lake's annual water budget, the effect of plant water withdrawal on the reduction of phosphorous discharged to the lake from TC/NS is significant. Based on the data presented in the "Interim Surface Water Improvement and Management Plan" (SFWMD, 1989) and Section 2.3.4.1, approximately 143 tons of phosphorous are discharged from TC/NS to Lake Okeechobee annually. The plant water withdrawal of 7.5 cfs can reduce the annual discharge of phosphorous to the lake by 7.3 tons. This amounts to 1.2 percent reduction of total phosphorous to Lake Okeechobee annually.

5.3.1.3 <u>Groundwater Level</u>

During prolonged drought conditions, lowering the canal water levels can lower the adjacent connected water table of the Surficial aquifer and consequently affect any wells and wetlands located in the area influenced by the lowered water table. The extent of such an effect is mainly a function of canal water level drop and its duration.

To quantify such effects, an analysis was made to estimate the impact of lowering the canal water level caused by plant water withdrawal on the adjacent surficial water tables. The method of analysis was based on one-dimensional unsteady computerized groundwater flow in an unconfined aquifer as discussed by McWhorter and Sunada (1977).

The adjacent surficial aquifer properties are estimated from the reference materials (SFWMD, 1987; Ardaman & Associates, 1989; CH2M Hill, 1990; USDA, 1971 and 1981). The geological formation of surficial aquifer consists of shell, sandstone, limestone, and fine sand (SFWMD, 1987; USDA, 1971 and 1981). The estimated hydraulic conductivity of the top 30 feet of the Surficial aquifer at the vicinity of the TC/NS canals is about 5×10^{-3} cm/s (SFWMD, 1987; Ardaman & Associates, 1989; CH2M Hill, 1990; USDA, 1971 and 1981). The specific yield of the surficial aquifer is 0.2, within the normal range for this parameter (SFWMD, 1987).

In the analysis, it was assumed the water level in the aquifer is initially the same level as the canal water level. A water level drop scenario representing a severe drought condition, was selected. The canal water level was dropped by 2.5 feet in 40 days and was maintained at that level for an additional 90 days. Then the canal water level was raised by 2.5 feet in 20 days, and was maintained at this final level for an additional 30 days (Figure 5.3.1-17). A total of 180 days was used for simulation.

From the analysis, the total number of days at which the groundwater level dropped more than 1 foot is found for selected distances from the canal. These are presented below:

Distance from the Canal (ft)	Total No. of Days
100	116
300	87
500	28
700	0

For the simulated drought scenario, the 1-foot drop in water table does not extend to a distance of 700 feet from the canal throughout the simulation time.

The simulated drought condition is more severe than the drought condition of 1981 (Figure 5.3.1-8). As discussed in Section 10.9, the drought condition of 1981 is the most severe during the available period of precipitation data. In addition, the annual precipitation during 1981 was the lowest of 34 years of record for Port

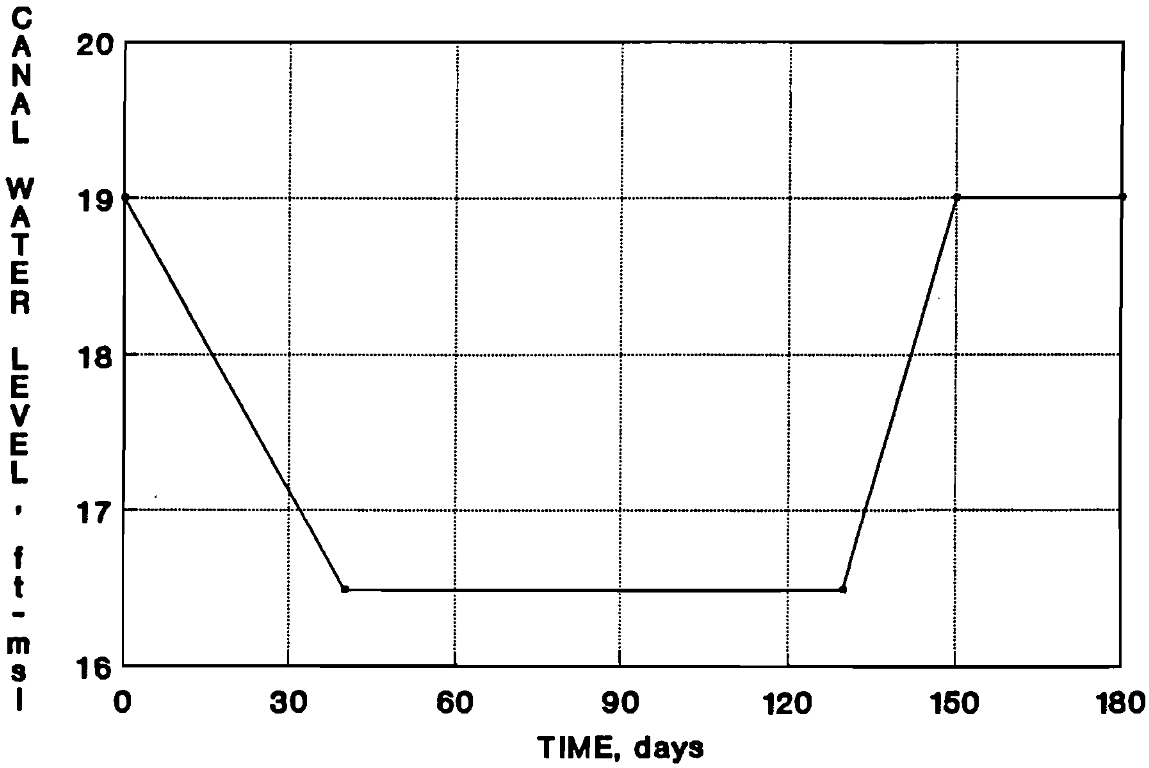

Figure 5.3.1-17.

CANAL WATER LEVEL SCENARIO USED FOR GROUNDWATER LEVEL IMPACT ANALYSIS

Source: Bechtel, 1990

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Mayaca Station. Furthermore, since the pumping of the plant water from the canals will be stopped at the low water level of 16.5 feet-MSL, the impact of such a drought on the groundwater table should be minimal and the 1-foot lowering should be limited to a distance of about 500 feet from the canal.

5.3.1.4 Impact on Other Surface Water Users

Three existing agricultural water users from Taylor Creek are reported and are listed in Table 2.3.3-5. From this table, two of the users are on the old section of Taylor Creek, which is connected to Lake Okeechobee, and one potential user with annual allocation of 94 MG (180 gpm) is on Canal L-63N.

As discussed in Section 5.3.1.1, the canal water levels are not affected by the plant water consumption in a normal year. During severe drought conditions, the canal water level may drop 2 to 3 feet below normal operating water level, resulting in a lower head at the intake of the above potential user. However, since low water level periods last for a short period of time, the impact of such low water level on the water withdrawal capability of the user should be minimal.

5.3.2 GROUND WATER

Both the Surficial and the Floridan aquifers are susceptible to potential impacts from operations at the ICL facility. The plant design was developed with an understanding of the aquifers' vulnerability, and, therefore, the proposed plan incorporates features to safeguard the aquifers and maintain pre-project water quality within the groundwater regime.

5.3.2.1 Surficial Aquifer Potential Contaminants

The Surficial aquifer occupies the upper 120 feet of sediments that underlie the site. The aquifer may be divided into two major water-bearing zones. An upper, unconfined or water table zone occurs within the layers of interbedded sand and silt which are exposed at the ground surface and extend to a depth of about 30 feet. A semi-confined zone, the major production interval of the Surficial aquifer, is composed of sand and shell layers which occupy an interval between 85 and 120 feet below the ground surface. These two water-bearing zones are separated by 55 feet of less permeable sand, silt and clay layers which restrict the vertical flow of groundwater between the two zones.

Throughout the site, the water levels within the upper, unconfined zone of the Surficial Aquifer are within 5 feet of the ground surface. During at least part of the year, the water table intersects portions of the ground surface, occurring as wetland ponds. The close proximity of the water table to the ground surface makes the Surficial Aquifer especially vulnerable to any contaminants that might enter the aquifer as seepage or leachate from the ground surface.

Potential sources of contamination would include the coal and lime stored onsite, the bottom ash and fly ash generated onsite, the cooling water storage pond, and any other solid or hazardous wastes generated onsite.

Coal storage will consist of an active use facility and a grassed, inactive pile, sized to store enough coal for 30 days at full load. The active use coal storage facility will be completely enclosed. Because the coal will not be exposed to the elements, leachate and runoff problems are eliminated. Section 5.3.4 discusses impacts on the Surficial aquifer due to leachate and runoff from the inactive coal storage area.

Small quantities of lime will also be utilized onsite as part of the coal burning process. Lime will be delivered by rail and stored in an enclosed facility prior to usage. Once again, the enclosed facility will eliminate the problems associated with leachate and runoff.

Section 5.4 addresses the disposal of solid and hazardous wastes at the site.

The cooling water storage pond will contain water from Taylor Creek/Nubbin Slough. As discussed in Section 3.5, the quality of this water is comparable to background water within the Surficial aquifer. However, the pond will be lined to keep pond seepage from mixing with the potable water of the Surficial aquifer.

Potential leakage from the wastewater injection well also represents a source of contamination to the Surficial aquifer. As described in Section 3.5.1.5, the many precautions and casing integrity tests that are required as part of injection well installation provide reassurance that no leak in the well casing could go undetected, either prior to or during wastewater injection operations.

As shown on Figure 2.3.2-3, the water table gradient is generally to the south toward the St. Lucie Canal. Potential offsite receptors of a hypothetical plume generated onsite include the St. Lucie Canal and two Surficial aquifer wells to the southeast of the site (Figure 2.3.3-1). As discussed in Section 5.3.5, the positioning of monitor wells along the southern boundary of the site ensures that no contaminant plume could move offsite undetected.

5.3.2.2 Floridan Aquifer Groundwater Withdrawals

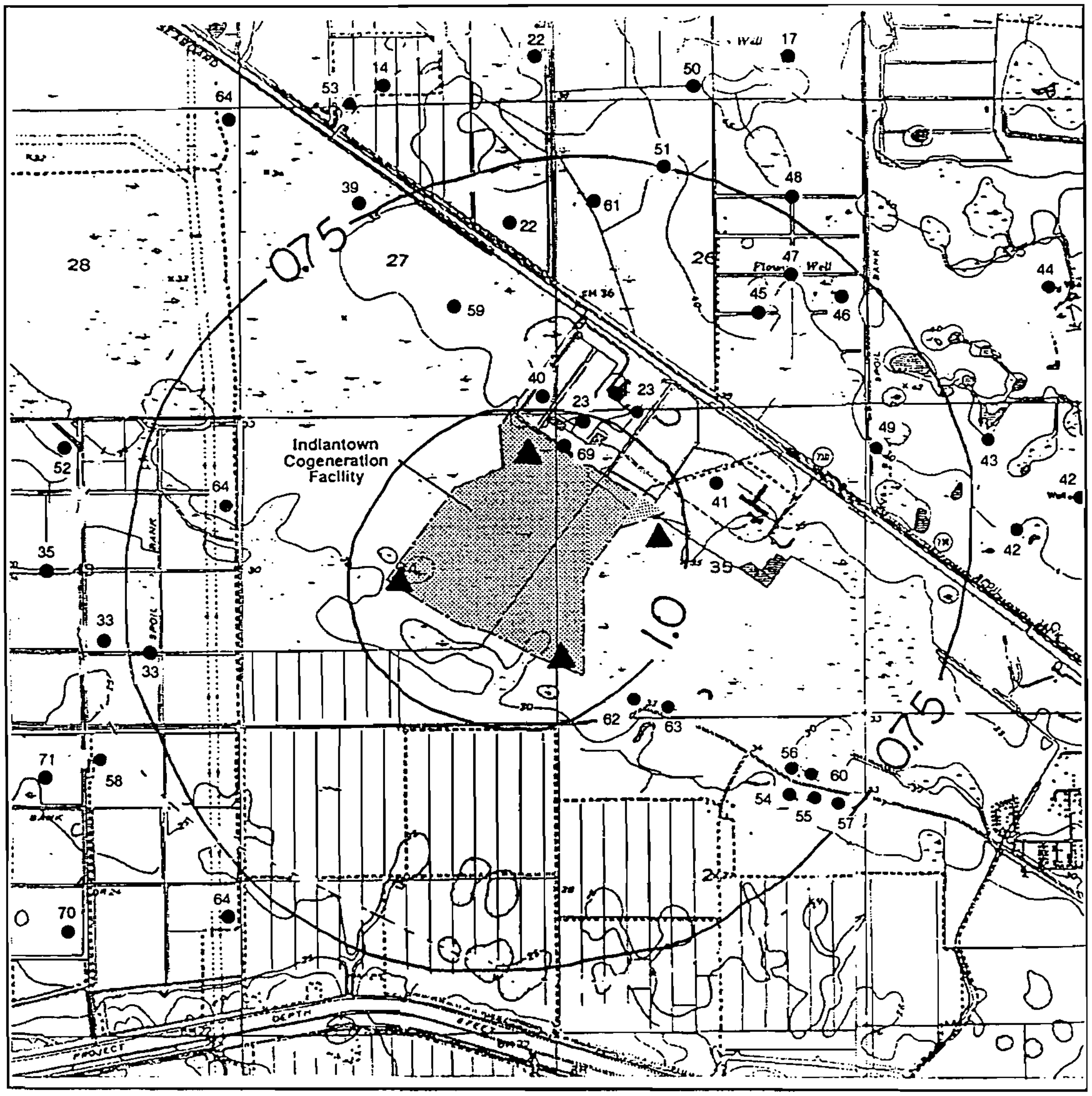
As discussed in Section 3.5, the analysis of historic water levels in Taylor Creek/Nubbin Slough indicates an alternative source of cooling water will be required for a maximum of 90 continuous days during an extreme drought year. The lower permeable horizon of the upper Floridan aquifer, which lies about 1,400 feet below the ground surface at the site, is proposed as this alternative source of water. A withdrawal rate of 4,000 gpm will be necessary to meet cooling water demand.

Figure 5.3.2-1 presents simulated drawdowns assuming 90 days of continuous flow from four 1,000 gpm wells, placed at the corners of the project site. Steady-state conditions are approached within the first day of withdrawal due to the extreme magnitude of transmissivity within this permeable horizon. Recovery rates will be just as fast. The projected drawdowns indicate negligible impacts upon the proposed FPL wells at the Martin Project Site.

Figure 5.3.2-2 presents the results of the 90-day simulation as they affect hydrostatic pressures within the uppermost permeable horizon of the Floridan aquifer. The model simulated drawdowns due to induced seepage of up to 0.9 foot in the immediate vicinity of the proposed wellfield.

The maximum capacity of free-flowing artesian wells is directly proportional to the height of the closed-in hydrostatic pressure above the well casing. In the project area, hydrostatic pressures are 15 feet above ground level. A decrease in hydrostatic head of about 1.5 feet equates to a 10 percent decrease in the maximum capacity of the well. The simulated maximum drawdown of 0.9 foot indicates that no existing well will experience a reduction of 10 percent in flow capacity.

To summarize, the plant design incorporates many features that will function to preserve the chemical quality of the Surficial aquifer. These features include totally



● EXISTING WELL

▲ SIMULATED WELL LOCATION

N ↑

ONE MILE

1000 4000
(Scale in ft)

Figure 5.3.2–1
SIMULATED DRAWDOWNS WITHIN THE LOWER PERMEABLE HORIZON OF THE FLORIDAN AQUIFER AFTER 90 DAYS OF FLOWING FOUR 1000–GPM ARTESIAN WELLS

Source: Bechtel, 1990; CH2M Hill

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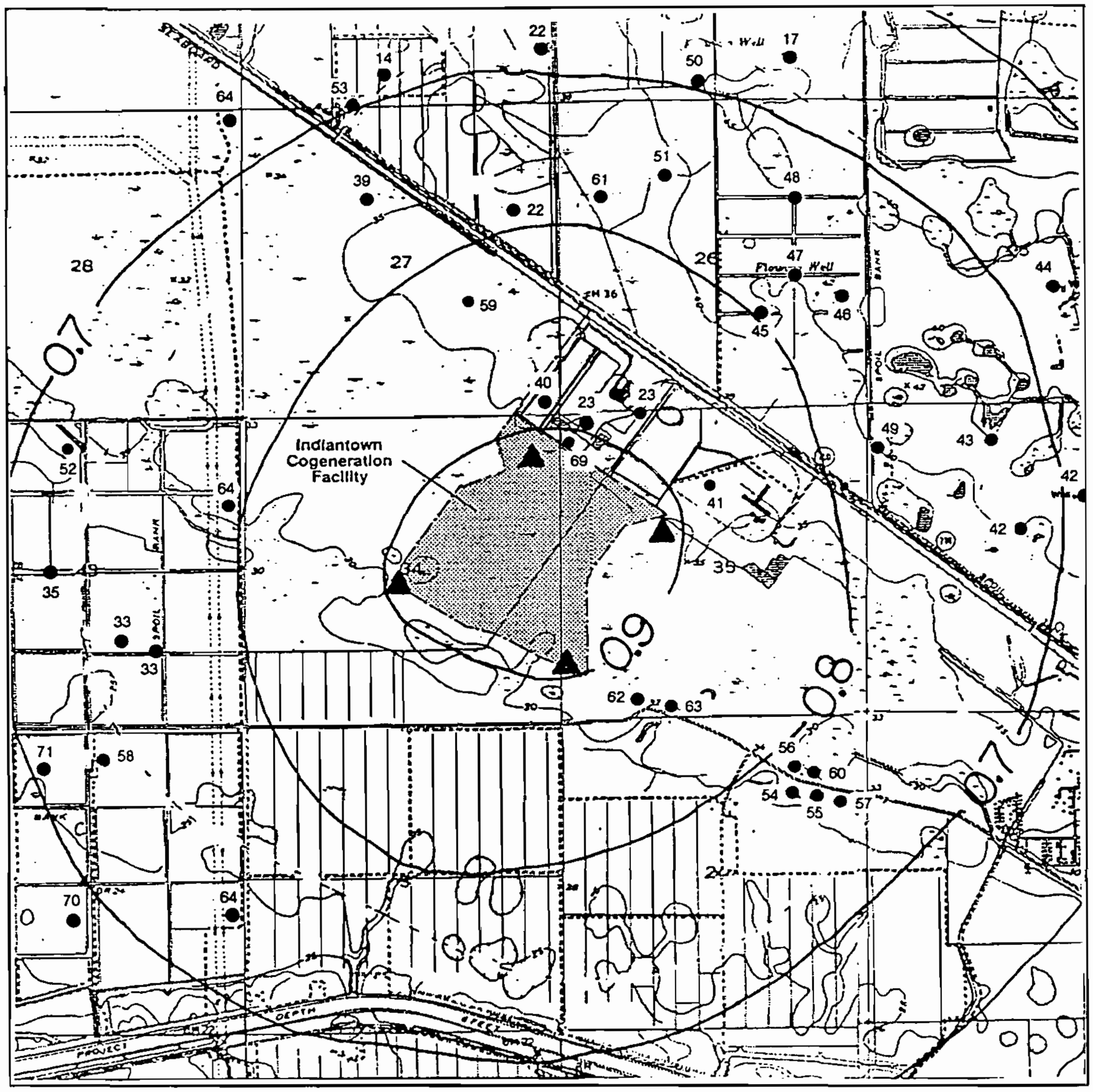

● EXISTING WELL

▲ SIMULATED WELL LOCATION

N

ONE MILE

1000 4000

(Scale in ft)

Figure 5.3.2–2
SIMULATED DRAWDOWNS WITHIN THE UPPERMOST PERMEABLE HORIZON OF THE FLORIDAN AQUIFER AFTER 90 DAYS OF FLOWING FOUR 1000–GPM ARTESIAN WELLS (SCREENED ACROSS THE LOWER, PERMEABLE HORIZON)

Source: Bechtel, 1990; CH2M Hill

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enclosed facilities for the active coal pile and lime storage areas, a lined inactive coal pile, a lined pond and basins, and procedures to remove wastes such as bottom ash and fly ash from the site. During normal dry and wet seasons, Taylor Creek/Nubbin Slough will provide plant cooling and process water.

When prolonged droughts occur, it will be necessary to withdraw water from the Floridan aquifer for cooling water at rates of 4,000 gpm for up to 90 days. Simulations of this withdrawal from the base of the upper Floridan aquifer indicate that induced seepage from the more heavily utilized parts of the upper Floridan will not exceed established criteria which protect existing users.

5.3.2.3 Alternative Source of Process Water During Drought Periods

As discussed previously, it is anticipated that there will be times when severe drought conditions cause water in Taylor Creek/Nubbin Slough to drop below the minimum intake level. It is also proposed to withdraw 300 gpm from the uppermost permeable horizon of the Floridan aquifer for process water purposes.

Withdrawals of 300 gpm for 90 days from the uppermost permeable horizon of the Floridan aquifer were simulated using analytical methods. The simulation results are included in Section 10.5.1 as a computer printout of input parameters and calculated drawdowns.

Figure 5.3.2-3 presents the simulated drawdowns caused by a single well, flowing at 300 gpm for 90 days. The figure shows that no existing Floridan aquifer wells will lose as much as 1 foot of hydrostatic head during the withdrawal period. As discussed in this section, the capacity of a free-flowing artesian well is directly proportional to the height that the hydrostatic head of the aquifer extends above the top of the well casing. At the project site, reductions of 1 foot in hydrostatic head would not reduce the flowing capacity of any existing well by as much as 10 percent. Therefore, withdrawals of 300 gpm for 90 days would not create drawdowns that would exceed SFWMD criteria for prohibitive well interference.

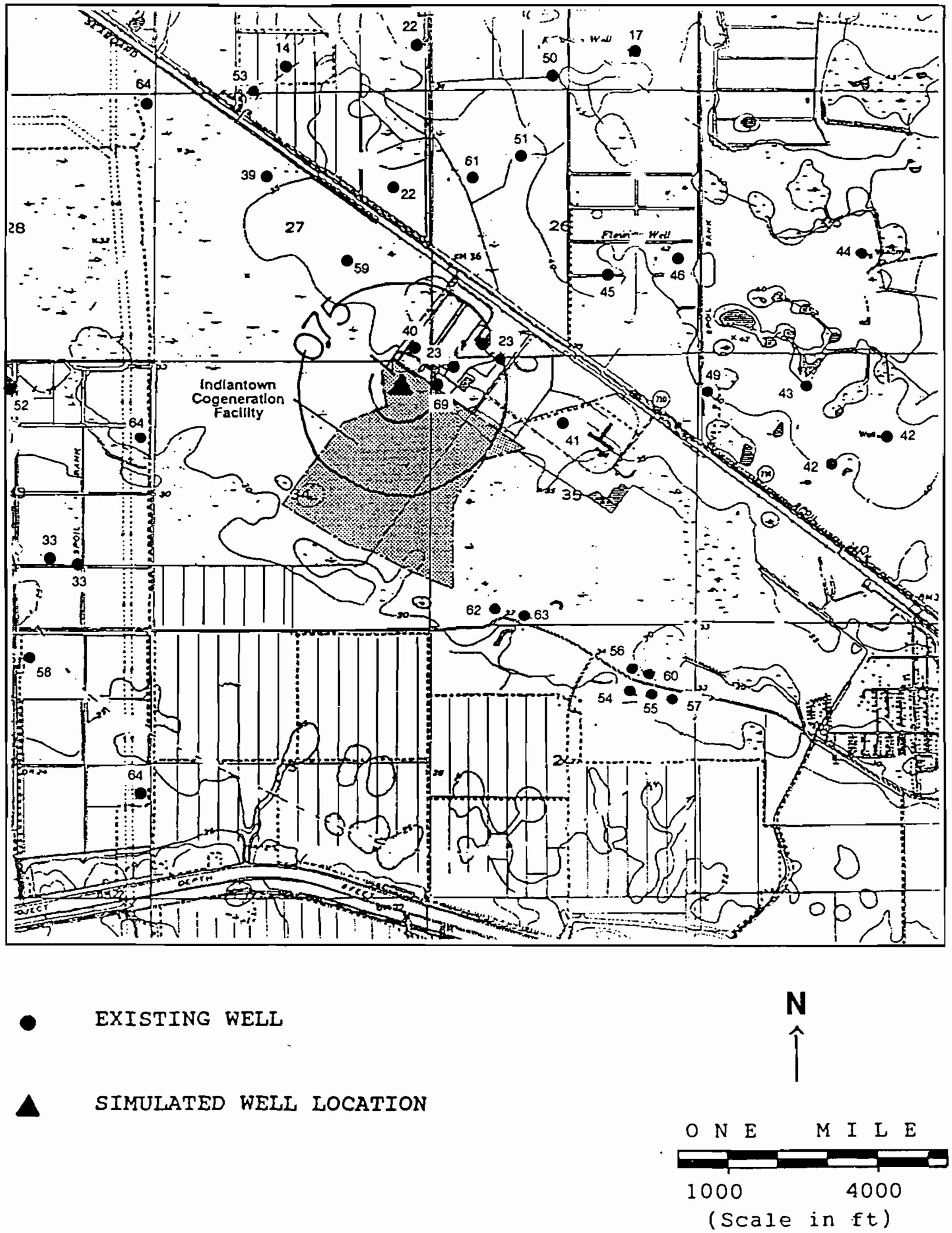

Figure 5.3.2–3
SIMULATED DRAWDOWNS WITHIN THE UPPERMOST PERMEABLE HORIZON OF THE FLORIDAN AQUIFER AFTER 90 DAYS OF CONTINUOUS FLOW FROM ONE 300 GPM WELL

Source: Bechtel, 1990; CH2M Hill

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5.3.3 DRINKING WATER

In the project area, the potable water supply is the Surficial aquifer. Figure 2.3.3-1 and Table 2.3.3-6 in Section 2.3.3 show the locations of wells within 1 mile of the site boundaries, and list well owners, permit numbers, well construction specifications, and purpose of the well (industrial, agricultural, potable use).

Because no water will be withdrawn from the Surficial aquifer for plant use, there will be no impacts on surrounding wells into the Surficial aquifer that withdraw water for drinking purposes.

The regional groundwater gradient is almost due south at 8 feet per mile. This results in seepage velocities of 20 to 80 feet per year, depending upon sediment porosity. It is conceivable that wells 62 and 63 on Figure 2.3.3-1 might intercept a hypothetical contaminant plume generated at the project site. However, the monitor wells installed into the Surficial aquifer on the site are positioned to detect any contaminant plume before it crosses property lines. Should an event such as a spill take place, these wells would be used to detect the plume in advance of it reaching an existing user, thereby allowing time for remedial action to be implemented.

5.3.4 LEACHATE AND RUNOFF

The only source of leachate or runoff that could adversely impact the Surficial aquifer is the inactive coal storage area. The inactive coal storage area will be covered and lined as described in Section 3.3.1. In addition, runoff and leachate from rainfall will be treated and collected in the adjacent coal pile runoff basin, as described in Section 3.6.2. The active coal pile will be enclosed and a physical barrier to the groundwater will be installed beneath the coal pile.

The inactive coal storage area is grassed over. Approximately 25 to 30 percent of the rainfall percolates through the grass to contact the coal. The composition and characteristics of leachate from coal piles varies substantially depending on the source of the coal. The leachate from the coal storage area is estimated to contain 7500 mg/l of total dissolved solids, 5000 mg/l sulfate, 200 mg/l iron, and a pH in the range of 3 - 4. The quality of the runoff (which only contacts the grass) is much better than the quality of the leachate, effectively diluting the leachate. Runoff and leachate are treated to adjust the pH prior to entering the coal pile runoff basin, as described in Section 3.6.2. Treated runoff and leachate from the coal pile runoff basin are transferred to the sidestream softener of the cooling tower.

Runoff from other areas of the plant (as discussed in Section 3.8) are directed to the existing drainage ditch which eventually leads to the St. Lucie Canal.

Activities Affecting Discharge to Surface Water Bodies

Excess runoff due to an increase in impervious areas causes runoff quality and quantity changes. Due to a higher runoff coefficient caused by increased impervious area, onsite stormwater runoff will increase. In order to maintain the pre-developed peak flow in the existing drainage ditch, detention basins will be employed to store excess runoff. The runoff from the plant area to the ditch will be controlled by methods described in Sections 3.8.4. and 3.8.5. Since peak flows before and after site development will not be changed, no adverse impacts concerning quantity of flow are anticipated.

For paved areas and areas where grease or oil may be blended with the runoff (e.g., switchyard, oil storage tank, railroad, parking lot, and power block), catch basins will be used in conjunction with oil/water separators for removal of the oil/grease deposits.

The runoff from the inactive coal storage area will be detained in the lined coal pile runoff basin and treated to adjust pH. Treated runoff will be transferred to the cooling tower sidestream softener and used in the cooling tower.

By detaining and treating water where needed, the quality and quantity of the water in the existing drainage ditch will be maintained. The existing drainage ditch in the plant area is a continuation of a drainage ditch extending from State Route 710 and extends 2.5 miles further to the St. Lucie Canal. Since the drainage ditch will not be adversely affected, the St. Lucie Canal likewise will be unaffected.

The mitigation measures to control impacts to the wetland adjacent to the cooling water storage pond are discussed in Section 3.8.5.2. The remaining six wetlands within the property boundaries have been analyzed, and it has been determined that no significant drainage pattern changes will be made. Based on the developed plan, it can be concluded that there will be no adverse impacts to the wetlands.

Flood Plain Encroachment

The ICL site is entirely within Zone B (100- to 500-year flood plain area) as defined by Insurance Rate Maps. Therefore, there will be no encroachment on the 100-year flood plain and offsite impacts on the 100-year flood level are precluded.

5.3.5 MEASUREMENT PROGRAMS

Section 3.5.1.5 describes the monitoring well that will be installed to detect changes caused by possible migration of the wastewater injected into the Boulder Zone of the lower Floridan aquifer upwards into the upper Floridan aquifer. Since there are no wastewater discharges to surface waters or to other groundwater aquifers, no other monitoring programs are proposed.

5.4 SOLID/HAZARDOUS WASTE DISPOSAL IMPACTS

5.4.1 SOLID WASTE

The Indiantown Cogeneration, L.P. (ICL) plant will generate solid waste from the combustion of coal, operation of the water and wastewater treatment system, and operation of the flue gas cleaning system. In addition, miscellaneous solid wastes such as general office refuse and maintenance wastes will be produced.

As discussed in Section 3.7.1, there will be no onsite disposal of solid waste.

5.4.1.1 Bottom Ash and Fly Ash

Bottom ash and fly ash will be removed from the site on rail cars for disposal at the coal mine. The ash will be disposed of in areas that have been worked out. These areas do not generally serve another purpose. Therefore, there will be no impact on usage of the disposal area.

5.4.1.2 Other Solid Wastes

All other solid wastes generated on the site (filter cake from the water and wastewater treatment system, office wastes, non-hazardous maintenance wastes) will be transported offsite for disposal in licensed solid waste facilities.

The Palm City Landfill No. 2 in Martin County has capacity to remain functional beyond the year 2000 (Martin County, 1989). The ICL plant will consume less than 1.5 percent of the available capacity at the landfill between the time the plant opens and the year 2000. As discussed in Section 3.7.1, the amount of water and wastewater treatment filter cake generated by the plant is greatly affected by the extent to which the backup water sources must be used. If the backup water sources are not required before the year 2000, the solid waste from the plant will consume less than 0.2 percent of the capacity of the landfill.

Martin County is currently studying options to dispose of solid waste after the existing landfill capacity is reached (Martin County, 1990). Impacts of the continuing operation of the ICL plant beyond the year 2000 cannot be quantified until a solid waste management program is finalized by Martin County.

5.4.2 HAZARDOUS WASTE

The ICL plant may generate hazardous wastes in the form of chemical product storage and transfer wastes, or other miscellaneous wastes.

As discussed in Section 3.7.2, there will be no treatment of hazardous wastes unless the treatment occurs in an "elementary treatment facility" or a "wastewater treatment unit" as defined by FDER and EPA hazardous waste regulations. In addition, hazardous wastes will not be stored onsite in excess of 90 days or such other period as FDER or EPA regulations allow.

Hazardous wastes generated onsite will be collected and stored in segregated storage areas, then transferred offsite by a licensed hazardous waste contractor for treatment of disposal. As discussed in Section 3.7.2, the volume of these wastes will be small and is not expected to result in significant impacts to treatment system capacity or land use.

5.5 SANITARY AND OTHER WASTE DISCHARGES

All other plant wastewater, other than sanitary, have been addressed in Section 5.2.

All sanitary wastewater generated at the Indiantown Cogeneration, L.P. (ICL) plant are transferred to the Indiantown Company water services sewer connection. There is no onsite treatment of sanitary wastewater. The average daily discharge of sanitary wastewater is less than 2 gpm. No significant impact on the Indiantown Company wastewater treatment system is expected from this small flow since the system is designed for 1.0 MGD capacity.

5.6 AIR QUALITY IMPACTS

5.6.1 IMPACT ASSESSMENT

This section summarizes the air quality impact assessment for the proposed Indiantown Cogeneration, L.P. (ICL) facility, as documented in the Prevention of Significant Deterioration (PSD) of Air Quality permit application contained in Section 10.1.5.

5.6.1.1 Regulatory Applicability and Scope of Analysis

The ICL site is located in Martin County, Florida, and is included in the Southeast Florida Intrastate Air Quality Control Region (AQCR) (40CFR81.49). The area immediately around the facility is in attainment or cannot be classified for all criteria air pollutants (i.e., meets the ambient standards) (40CFR81.310). Palm Beach County, about 9 km south of the site, is the only non-attainment area (for ozone) in the vicinity of the proposed facility. Martin County and the surrounding counties are designated as Class II PSD areas for SO_2, NO_2, and particulate matter (TSP) (40CFR 52.21(e)(3)). There are no Federal Class I PSD areas within 50 km of the proposed site. The closest Class I PSD area is the Everglades National Park (40CFR81.407) located about 140 km to the south.

The ICL facility is a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr heat input and has the potential to emit more than 100 tons/year of any regulated pollutant. It is therefore considered to be a new, major stationary source (40CFR52.21(b)(1)).

New, major stationary sources proposed to be located in an attainment area are subject to the Federal PSD regulations; in this case, as implemented by the State of Florida. PSD review is required for any regulated pollutant with a net emissions increase greater than specific levels considered to significant by EPA.

Table 5.6.1-1 lists the maximum expected total emissions for the facility and the corresponding significant emission levels.

This review includes an analysis of air quality impacts to demonstrate that the ambient standards will be met and that incremental impacts due to the new source will not exceed specified amounts. Under PSD, a control technology must be selected and defended for all pollutants emitted at significant levels. The objective is to achieve the maximum reduction in emissions, using current technology, while taking into consideration energy requirements and environmental and economic impacts. This process is referred to as the Best Available Control Technology (BACT) analysis, and is discussed in Section 3.4.3. These controls must be applied when the plant becomes operational. Finally, an analysis of other air quality-related effects associated with the project must be performed, including impairment to visibility; cooling tower effects (Section 5.1.4); impacts from industrial/residential growth that may occur because of the project; impacts on soils and vegetation in the site area; and potential health risks due to trace element emissions from the facility. The following subsections summarize additional details, including the results of these analyses.

5.6.1.2 <u>General Modeling Approach</u>

The air quality impact assessment consisted of a determination of the significant impact area for the plant, a PSD increment consumption analysis, a demonstration of compliance with federal and state ambient air quality standards, and an evaluation of other air quality-related effects (see Section 5.6.1.1). Methodologies followed EPA and FDER modeling guidelines, as appropriate. An air quality modeling protocol was prepared by the applicant and approved by the FDER prior to conducting the various analyses. The following subsections summarize key elements of the analytical approach and input information. A detailed discussion is found in Sections 3 and 4 of the PSD permit application in Section 10.1.5 of this report.

TABLE 5.6.1-1
PSD SIGNIFICANT EMISSION RATES AND MAXIMUM TOTAL EMISSION RATES FOR THE PROPOSED INDIANTOWN COGENERATION PROJECT

Pollutant	Significant Emission Rate (tons/yr)[a]	Maximum Total Emission Rate (tons/yr)[b]	BACT and AQ Analysis Required?
Particulate Matter (TSP)	25	306.1[c]	Yes
PM-10	15	276.2[c]	Yes
Sulfur Dioxide	40	2629.4	Yes
Nitrogen Oxides	40	2850.5	Yes
Volatile Organic Compounds	40	56.6	Yes
Carbon Monoxide	100	1858.4	Yes
Lead	0.6	0.152	No
Mercury	0.1	0.172	Yes
Beryllium	0.0004	0.041	Yes
Fluorides	3	22.26	Yes
Asbestos	0.007	0	No
Vinyl Chloride	1	0	No
Total Reduced Sulfur	10	0	No
Hydrogen Sulfide	10	0	No
Reduced Sulfur Compounds	10	0	No
Sulfuric Acid Mist	7	6.51	No
Any other pollutant regulated under Clean Air Act	Any rate	-----	---
Benzene		0	No
Inorganic Arsenic		0.766	Yes
Each regulated pollutant	Any rate causing an impact of 1 (24-hr average) or greater in any Class I area within 10 km of source.		No[d]

a - Source: 40CFR52.21(b).

b - Maximum total emissions are based on the maximum hourly emission rate; 8760 hrs/yr and 1000 hrs/yr of operation for the main and auxiliary boilers, respectively, with an annual load factor of 100 percent for both boilers.

c - Maximum total TSP and PM-10 emissions are conservatively assumed to be the same and include fugitive emission sources listed in Table 4-2.

d - The closest Class I PSD area is the Everglades National Park located about 140 km south of the proposed ICL plant. Therefore, air quality analyses are not required on this basis.

Source: Bechtel, 1990

Dispersion Model Selection

The analysis referred to above required the use of three different dispersion models to estimate:

- Incremental impacts due to the proposed and nearby sources

- Potential visibility impairment due to emissions from the ICL plant stack

- Cooling tower drift and deposition

Incremental air quality impacts were determined using the EPA Industrial Source Complex - Short Term (ISCST) dispersion model (EPA, 1987). The model was selected because of its ability to simulate the dispersion of emissions from multiple point and area sources. In addition, the model is capable of accounting for building wake effects on dispersion, allowing for variable emission rates with time and meteorological conditions (e.g., wind erosion), and considering the effects of particle deposition by gravitational settling. This latter phenomenon occurs with a significant fraction of the relatively large particle sizes found in fugitive dust emissions. These capabilities have resulted in EPA's designation of ISC as the preferred model for estimating concentrations from sources with these characteristics (EPA, 1986).

Potential visibility impairment on the distant Everglades National Park (140 km to the south) was estimated using the EPA Visibility Screening (VISCREEN) model. The algorithms are based on the technical guidance provided in the Workbook for Visual Plume Impact Screening and Analysis (EPA, 1988). The model evaluates particulate and NO_x stack emissions under hypothetical worst-case meteorological conditions. Visual impairment is quantified in terms of atmospheric discoloration from NO_x, particulate, and secondary aerosols, and visual range reduction (i.e., increased haze) from particulates and sulfates. Additional information is presented in Section 6 of the PSD permit application (see Section 10.1.5).

Emissions Data

Sources of airborne pollutants at the ICL plant consist of stack emissions from the coal-fired main boiler (under various load conditions), emissions from an auxiliary boiler fired by either No. 2 fuel oil or natural gas (and released from a separate stack), and fugitive dust emissions generated by material handling and storage activities. These activities include coal unloading, conveyance, transfer, and crushing; and ash and lime handling. Other nearby sources of air pollutants, either located within or having a significant impact on the modeled SO_2 and NO_2 impact areas caused by the plant, were determined in consultation with the FDER.

Maximum incremental impacts due to plant stack emissions were based on either SO_2 emissions from the main boiler at full (100 percent) load or the No. 2 oil-fired auxiliary boiler, also at full load. The respective SO_2 emission rates for these two operating scenarios are 582.6 lbs/hr and 17.73 lbs/hr. Impacts for other criteria and trace element pollutants were scaled in proportion to the respective emission rates for these pollutants to the SO_2 emissions. Detailed emissions information for the ICL plant (stack and fugitive) and other nearby sources is presented in Section 4 of the PSD permit application (see Section 10.1.5). Trace element emission rates are discussed in Section 5.1.4 of the PSD permit application.

Stack Height

A single stack will be used to exhaust emissions from fuel combustion in the main boiler. The height of the stack, approximately 495 feet, conforms to good engineering practice (GEP) regulations established by the EPA (1985). The regulations were promulgated to ensure that the emission control limitation required for any pollutant would not be affected (i.e., made less stringent) by the increased dispersion (and decreased impacts) resulting from a stack which exceeds GEP height, or by any other dispersion technique. Section 123 of the Clean Air Act defines GEP stack height as:

> "...the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, or wakes created by the source itself, nearby structures, or nearby terrain obstacles."

While a source may construct a stack to any height allowed under any other regulation, credit may be taken only up to the GEP height, if the actual height is greater than GEP. Therefore, construction of the ICL plant stack for the main boiler to GEP height will avoid downwash effects and the resulting "excessive concentrations" compared to a stack with a lower height.

On the other hand, a separate stack (90 feet high) will be used to vent emissions from the auxiliary boiler. This stack is adjacent to the main boiler building, which is a taller structure, and this stack is therefore less than GEP height. As a result, wake effects were considered in the dispersion analysis of auxiliary boiler emissions. This configuration does not lead to "excessive" impacts as the results in Section 5.6.1.3 demonstrate.

Meteorological Data

The air quality modeling analyses were based on sequential, hourly surface meteorological data and concurrent twice-daily upper air soundings from the National Weather Service (NWS) station at West Palm Beach, Florida, about 26 miles to the east-northeast. These data cover the 5-year period from 1982 to 1986 and were provided by the FDER.

In lieu of using onsite meteorological data, the EPA considers that use of a representative, offsite 5-year data set adequately reflects the range of dispersion conditions expected in the site area. Accordingly, highest second-highest, short-term modeled concentrations are used to determine total air quality impacts for comparison with ambient standards and for comparison against applicable PSD increment levels. Compliance with the ambient standards and PSD increments are written such that one exceedance of the corresponding numerical value is allowable during each calendar year. Use of the highest second-highest value presumes that one such an exceedance occurs. However, annual average total and incremental impacts are based on the use of the highest concentration from among the 5 years of modeled data because these long-term standards are not to be exceeded at any time.

Background Air Quality Levels

Total air quality impacts represent the sum of the incremental impact due to the proposed source, concentrations due to nearby emission sources (if expected to result in a significant concentration gradient within the impact area of the proposed source), and ambient background concentrations attributable to all other sources (e.g., natural sources, minor sources, and distant major sources). This third component, ambient background levels, may be determined by using site-specific monitoring data or measurements taken at nearby monitoring stations and demonstrated to be representative of conditions in the site area.

Site-specific monitoring data were not collected in the pre-construction phase of this project for two reasons. First, representative data from several nearby stations were available; and second, impacts due to the proposed source were estimated to be less than significance levels otherwise requiring monitoring to be conducted. An exemption from pre-construction monitoring was issued by the FDER for the ICL.

Three criteria are considered in determining whether data from existing monitoring stations are representative of conditions in the site area: (1) monitor location; (2) data quality; and (3) currentness of data. The FDER has indicated that data from the 1-year (October 1988 to September 1989), pre-construction PSD monitoring program for the FPL Martin CG/CC project (SO_2, NO_2, and PM-10), and from FDER stations in Martin and Okeechobee Counties (TSP) and Palm Beach County (CO), from 1987 to 1989, generally meet these criteria and considers these data acceptable for estimating total air quality impacts (FDER letter, July 23, 1990).

Background SO_2 levels are assumed to be 61 ug/m^3 (3-hour), 12.6 ug/m^3 (24-hour), and 1.3 ug/m^3 (annual average). For NO_2, a 1-hour average background value of 62 ug/m^3 and an annual average value of 5.4 ug/m^3 are used in the impact analysis. Short- and long-term ambient PM-10 levels are assumed to be 39 and 13.3 ug/m^3 on a 24-hour and annual average basis, respectively. Background TSP levels were based on the highest 24-hour average TSP concentration (105 ug/m^3) measured at the FDER site in Okeechobee County in 1989; and the highest annual average TSP value (40 ug/m^3) measured in Martin County, again in 1989. For CO, 1-hour and 8-hour average background values (8,001 and 5,766 ug/m^3, respectively) measured at the FDER station in Palm Beach County in 1988 were used.

The selection of these data is discussed further in Section 5.3.1 of the PSD permit application (see Section 10.1.5 of this report).

5.6.1.3 <u>Incremental Impacts</u>

This section summarizes the maximum incremental impacts due to emissions from the proposed ICL plant and other nearby sources. A PSD increment consumption analysis is required for SO_2 and NO_2 because the maximum concentrations attributable to the plant exceed the EPA significant impact levels. Maximum particulate impacts are below the corresponding significance levels and were not considered further in that regard. Based on discussions with the FDER, other nearby sources of SO_2 and NO_2 emissions that consume available increment levels in the site area were included in the analysis. A demonstration is also made that total air quality impacts for SO_2, NO_2, TSP, PM-10, CO, and lead will not exceed or threaten to exceed the national and State of Florida Ambient Air Quality Standards (NAAQS/FAAQS). As mentioned before, total air quality impacts represent the sum of the modeled incremental impact due to the proposed source, modeled concentrations due to nearby emission sources, and measured ambient background concentrations attributable to all other sources. An inventory of the other sources to be considered was developed in consultation with the FDER.

Finally, maximum incremental concentrations of trace element emissions (i.e., beryllium, fluorides, inorganic arsenic, and mercury) are estimated and compared to the corresponding FDER "no-threat" levels.

A detailed discussion of all of the above incremental impacts is found in Section 5 of the PSD permit application (see Section 10.1.5).

Maximum Incremental Impacts

This subsection summarizes the maximum incremental impacts for the criteria pollutants (SO_2, NO_2, TSP, PM-10, CO, and lead), as well as the non-criteria trace element emissions (beryllium, fluorides, inorganic arsenic, and mercury). Where appropriate, these values are compared with corresponding significant impact values. In the case of the trace element emissions, values are compared with threshold levels specified by the FDER as posing no threat to the public health.

SO_2 Impacts

SO_2 impacts from the proposed facility were estimated by the ISCST model (see Section 5.1.6.2). For short-term impacts, the highest second-highest concentrations are reported because the analyses were based on the use of 5 years of representative meteorological data. For long-term (annual) impacts, the overall maximum concentration estimated from among all 5 years was used.

Of the 5 years modeled, the maximum annual average concentration is 1.15 $\mu g/m^3$, only slightly more than the significance level of 1 $\mu g/m^3$. The maximum 24-hour average incremental value (11.6 $\mu g/m^3$) also occurs at the same location, 250 meters from the main stack. Emissions from the main boiler contribute nothing to these concentrations. These values are the result of building wake effects on the auxiliary boiler stack emissions that result when firing fuel oil. The 24-hour average value is above the 5 $\mu g/m^3$ significant impact level, but still below the significant monitoring threshold level of 13 $\mu g/m^3$. The maximum 3-hour average value (24.7 $\mu g/m^3$) occurs much farther downwind (about 2 km to the northwest). This concentration is due to auxiliary boiler emissions as well, but not the result of building downwash effects. This value is less than the corresponding 3-hour average significant impact level of 25 $\mu g/m^3$.

Overall, these results indicate that maximum impacts are dominated by emissions from the auxiliary boiler stack. SO_2 emission rates are greater from the main boiler. However, the dispersion that occurs, before the maximum impact location for this source is reached, offsets the difference in emissions relative to the auxiliary boiler. Because the 24-hour and annual average concentrations are above their corresponding significant impact levels, a PSD increment consumption analysis is required.

Particulate Impacts

Maximum incremental particulate impacts are due to fugitive dust emissions from material handling activities, rather than from the main or auxiliary boilers. Fugitive dust is generated near ground level, is non-buoyant, and undergoes gravitational settling. As a result, these impacts occur at the plant property line. Building wake effects influence the dispersion of auxiliary boiler stack emissions such that these impacts overlap the fugitive dust impact area. The composite results indicate that maximum incremental particulate concentrations are 3.3 $\mu g/m^3$ (24-hour average) and 0.26 $\mu g/m^3$ (annual average). The annual average value is a conservative estimate based on the sum of the maximum incremental concentrations from both source types, although the impact locations do not overlap.

These maximum short- and long-term values are below the corresponding significant impact levels (5 $\mu g/m^3$ for 24 hours, and 1 $\mu g/m^3$ for annual average). Therefore, a determination of PSD increment consumption is not required for this pollutant.

During operations, fugitive dust could be produced by truck traffic, loadout of lime for the FGD system, loadout of collected fly ash, and exposure of material that can easily become windborne. However, measures are planned to minimize their occurrence. Plant roadways carrying truck traffic will be paved, and those trucks carrying readily suspendible material will be either covered or enclosed. Provisions are made for dustless loadout of the material indicated above (e.g., pneumatic conveyance from enclosed trucks or railcars). The active coal storage pile will be enclosed. The inactive coal storage pile will be covered with soil and seeded. Areas of the site that were disturbed during construction, but not utilized during operation, will be seeded or covered with gravel, as appropriate, and left as open space.

NO_2, CO, and Lead Impacts

The maximum annual average SO_2 concentration (1.15 $\mu g/m^3$) is the result of emissions from the auxiliary boiler stack when fuel oil is burned. The ratio of the maximum hourly NO_x emission rate for the auxiliary boiler (68.2 lbs/hr) to the corresponding SO_2 emission rate (17.73 lbs/hr) is 3.847. The resulting maximum annual average incremental NO_2 value is 4.42 $\mu g/m^3$, which is greater than the 1 $\mu g/m^3$ significant impact level, but more than three times below the corresponding monitoring exemption level of 14 $\mu g/m^3$.

Maximum 1-hour and 8-hour average CO impacts were estimated directly by the ISCST model because of the disparity in the ratios of CO and SO_2 emission rates for the main and auxiliary boilers and the relative contribution of each source to the maximum modeled concentrations. The maximum 1-hour CO incremental impact is only 78.2 $\mu g/m^3$; the maximum 8-hour average value is 50.9 $\mu g/m^3$. Both of these impacts are due to auxiliary boiler emissions. The 1-hour value is about 25 times less than the corresponding significance level (2,000 $\mu g/m^3$). The maximum 8-hour value is about 10 times lower than the 8-hour significance level (500 $\mu g/m^3$).

Maximum estimated total lead emissions from the plant are less than the corresponding significant emission level (see Table 5.6-1); thus, no air quality analysis for lead is required.

Non-Criteria Pollutants

There are four non-criteria pollutants, which are trace elements, that will be emitted from the ICL main boiler in significant amounts. Maximum hourly emission rates for these pollutants are: beryllium (0.0094 lb/hr), fluorides (5.08 lbs/hr), inorganic arsenic (0.175 lb/hr), and mercury (0.067 lb/hr). The ratios of these emission rates to the maximum hourly SO_2 emission rate from the main boiler (582.6 lbs/hr) were determined. In turn, these ratios were used to scale the maximum incremental 8-hour, 24-hour, and annual average SO_2 concentrations due to the main boiler alone to determine the equivalent concen-trations for each of these non-criteria pollutants. The results were then compared to corresponding "no-threat" levels, developed by the Florida Air Toxics Working Group, to evaluate potential health effects because of these emissions.

Maximum incremental SO_2 impacts from the plant are due to emissions from the auxiliary boiler stack because of downwash effects on dispersion, as reported above. However, trace element emissions from the auxiliary boiler are, in general, three orders of magnitude lower than from the main boiler. The maximum incremental SO_2 concentrations due to the main boiler only are 13.1 $\mu g/m^3$ (8-hour), 5.7 $\mu g/m^3$ (24-hour), and 0.56 $\mu g/m^3$ (annual). Therefore, maximum trace element impacts will be due to emissions from the main boiler.

Maximum 8-hour, 24-hour, and annual average beryllium impacts are about two orders of magnitude less than the corresponding "no-threat" levels (0.02, 0.005, and 0.0004 $\mu g/m^3$, respectively). A similar difference in magnitude is shown for fluorides. The maximum 8-hour and 24-hour incremental concentrations are about 220 and 120 times less than the respective "no-threat" levels (25 $\mu g/m^3$ for 8 hours, and 6 $\mu g/m^3$ for 24 hours). A threshold level for fluoride has not been specified on an annual average basis.

Maximum 8-hour and 24-hour inorganic arsenic impacts are about two orders of magnitude less than the corresponding "no-threat" levels (2 and 0.54 $\mu g/m^3$, respectively). The maximum annual average incremental impact is 84 percent of the annual threshold value (0.0002 $\mu g/m^3$). For mercury, maximum 8-hour and 24-hour impacts are also about two orders of magnitude less than the respective "no-threat" levels (0.1 and 0.024 $\mu g/m^3$, respectively). Like fluorides, a threshold level for mercury has not been specified on an annual average basis.

Overall, it may be concluded that trace element emissions from the plant pose no significant health risk in the site area. A detailed discussion of this analysis is found in Section 5.1.4 of the PSD permit application (see Section 10.1.5).

PSD Increment Consumption Determination

As the previous subsection indicates, a determination of the amount of available PSD increment consumed by the ICL plant and other sources specified by the FDER is required for SO_2 and NO_2. Since maximum particulate impacts were shown to be insignificant, such a determination was not necessary for that pollutant.

Maximum composite SO_2 impacts for the 3-hour, 24-hour, and annual average periods are 176.8 $\mu g/m^3$, 49.4 $\mu g/m^3$, and 3.98 $\mu g/m^3$, respectively, and occur at distances greater than 3 km from the ICL stack to the west and northwest. These values are about 35, 54, and 20 percent of the corresponding maximum allowable PSD increment levels (i.e., 512, 91, and 20 $\mu g/m^3$, respectively). The ICL plant contributes nothing to the combined maximum 3- and 24-hour incremental impacts, and only about 13 percent to the annual composite impact level. This demonstrates that operation of the facility poses very little threat of exceeding allowable increment levels.

For NO_2, the maximum composite annual average incremental impact is 6.53 $\mu g/m^3$ and occurs adjacent to the eastern part of the ICL property line. Auxiliary boiler emissions contribute about 68 percent of this impact. However, this value is only about 26 percent of the corresponding maximum allowable increment level (25 $\mu g/m^3$). As with SO_2, the composite results demonstrate that operation of the proposed facility poses very little threat of exceeding allowable increment levels.

Ambient Air Quality Compliance Demonstration

As a conservative approach, maximum incremental concentrations of criteria pollutants, due to emissions from the ICL plant and other nearby sources, were evaluated within the SO_2 significant impact area around the site. This impact area extends 4.25 km downwind.

Maximum SO_2 impacts within this study area are not significantly influenced by emissions from the ICL plant. On the contrary, maximum concentrations due to other nearby sources impacting the study area are 182.0 $\mu g/m^3$ (3-hour), 48.5 $\mu g/m^3$ (24-hour), and 6.77 $\mu g/m^3$ (annual). When combined with the respective monitored ambient background levels (61.0, 12.6, and 1.3 $\mu g/m^3$), the resulting total impacts are 243.0 $\mu g/m^3$ (3-hour), 61.1 $\mu g/m^3$ (24-hour), and 8.18 $\mu g/m^3$

(annual), respectively. All total impacts are well below the corresponding NAAQS/FAAQS.

Maximum particulate impacts within the study area are dominated by fugitive emission sources at the ICL site, and are 3.3 $\mu g/m^3$ for 24 hours and 0.26 $\mu g/m^3$ on an annual average basis. For this analysis, these concentrations are assumed to apply to particles in the TSP and PM-10 size ranges. Total TSP impacts, using the background values reported in Section 5.6.1.2, are 108.3 and 40.26 $\mu g/m^3$ for 24-hour and annual average periods, respectively. These values are below the state primary and secondary TSP standards. For PM-10, measured background levels of 39.0 and 13.3 $\mu g/m^3$ are used to determine 24-hour and annual average total impacts of 42.3 and 13.56 $\mu g/m^3$, respectively. These values are below the corresponding ambient standards of 150 $\mu g/m^3$ (24-hour) and 50 $\mu g/m^3$ (annual average).

Total annual average NO_2 impacts within the study area are based on an incremental concentration of 4.42 $\mu g/m^3$ from the ICL plant, 1.68 $\mu g/m^3$ from other nearby sources, and a monitored ambient background level of 5.4 $\mu g/m^3$. The total value (11.5 $\mu g/m^3$) is far below the federal and state ambient standard (100 $\mu g/m^3$).

Maximum incremental CO impacts for 1- and 8-hour averaging periods due to the ICL plant were determined to be 78.2 and 50.9 $\mu g/m^3$, respectively. When combined with the assumed background CO levels (see Section 5.6.1.2), the total impacts (8,079 $\mu g/m^3$ for 1 hour, and about 5,766 $\mu g/m^3$ for 8 hours) are well below the corresponding NAAQS/FAAQS of 40,000 and 10,000 $\mu g/m^3$.

Overall, it may be concluded from these results that emissions from the proposed facility alone or in combination with other nearby sources are well below the federal and state ambient air quality standards and pose no threat of causing an exceedance. Section 5.3 of the PSD permit application provides more detail with respect to this compliance demonstration (see Section 10.1.5).

5.6.1.4 Potential Visibility Impairment

A Level-1 analysis was made to determine the potential for visibility impairment at the Everglades National Park, 140 km south of the ICL, the closest Class I PSD area to the site. The Level-1 analysis makes conservative assumptions with respect to meteorological conditions and maximum stack emission rates. The model generates critical indices for plume perceptibility and plume contrast against the sky or terrain and compares these values to threshold levels. An exceedance of these values indicates that some type of visibility impairment is possible and that a more refined analysis (e.g., incorporating more detailed emission characteristics and actual meteorological data) is necessary.

The results of the Level-1 VISCREEN analysis indicate that all indices for plume perceptibility and contrast are below these threshold levels. The screening results also demonstrate that the farthest distance at which the ICL stack plume might be observed is between 60 and 65 km away. Overall, these results are not unexpected, considering the source-receptor separation, that emissions will be controlled through the application of BACT, and that opacity of emissions from the facility will be limited to 20 percent or less. Therefore, it may be concluded that operation of the ICL plant will not impair visibility.

A more detailed discussion of the potential visibility impact analysis is found in Section 6 of the PSD permit application (see Section 10.1.5).

5.6.1.5 Other Air Quality-Related Effects

Several air quality-related effects have been addressed in previous sections: potential health risks of trace element emissions (Section 5.6.1.3); impairment to visibility (Section 5.6.1.4); and cooling tower impacts (Section 5.1.4). This section addresses the other effects required to be evaluated under the PSD review process: impacts from industrial/residential growth that may occur because of the project; and impacts on soils and vegetation in the site area.

Potential Growth Impacts

The area surrounding the ICL site is currently zoned as agricultural and has been historically used for the same purposes. There are a few isolated rural industrial facilities, as evidenced by the Caulkins Citrus processing plant (the steam host facility for the project). No areas of special value, scenic vistas, or recreational areas exist within the immediate site area.

Minimal growth associated with the construction and operation of the plant is expected. An adequate work force currently exists in the site area to support construction without the need for importing workers, although some temporary relocations will occur. During operation, some additional relocation of plant personnel will be required. However, in both cases, these numbers will be within planned area growth projections and will not be the cause of any increased development.

Process steam will be consumed by the host facility and some will be used for electrical power generation. Some of the power is intended to satisfy in-house loads; most will be sold to FPL. Therefore, no direct effect of electrical or steam production on industrial or residential growth is expected in the site area.

As a result, no air quality-related impacts, directly attributable to the expected minimal growth associated with the proposed plant, are anticipated. Construction and operation of the plant will eliminate the cattle grazing that currently occurs on the site.

Potential Impacts on Soils and Vegetation

The primary effect of SO_2 and NO_2 deposition and absorption by soils is the resultant lowering of soil pH. Low soil pH will have an influence on most chemical and biological reactions in the soil: it accelerates mineral weathering and the release of phytotoxic ions to the soil solution; it affects the migration of clay and organic materials down through the soil-profile development process; and it will affect the level and availability of most plant nutrients in the soil. Based on the maximum incremental and total SO_2 and NO_2 impacts discussed in Section 5.6.1.3 and the fact that they are well below the NAAQS/FAAQS, adverse effects on soils in the site area are not anticipated.

Particulate deposition may affect soils by altering soil pH and by potentially increasing the availability of heavy metals in the soil for plant uptake. However, it has also been determined that uptake by vegetation will not increase dramatically unless the deposited trace elements are considerably more available than endogenous forms. Considering the results in Section 5.6.1.3, those levels are not expected to be surpassed.

Potential impacts to vegetation from SO_2 and NO_2 have been evaluated with respect to dose response curves that have been developed for various plant species and their sensitivity to these pollutants. Plants have been ranked as sensitive, intermediate, or resistant in this regard.

For SO_2, the lowest 3-hour concentration expected to cause injury or damage to sensitive vegetation is about 390 $\mu g/m^3$. From Section 5.6.1.3, the highest incremental 3-hour average SO_2 impact is 24.7 $\mu g/m^3$ due to the ICL plant alone, and 182.0 $\mu g/m^3$ for the plant and other, nearby sources combined. The maximum total impact, which includes a background level of 61.0 $\mu g/m^3$, is 243 $\mu g/m^3$, or about two-thirds of the sensitive species threshold value for possible injury. It is reasonable to conclude that operation of the plant will not damage vegetation in the site area based on SO_2 emissions from the proposed facility alone or in combination with other existing nearby sources.

A similar conclusion is drawn with respect to potential injury to vegetation resulting from NO_2 emissions. Threshold levels of response for 3-hour and 24-hour averaging periods are 1,890 and 750 $\mu g/m^3$, respectively. Maximum 3-hour and 24-hour incremental NO_2 impacts due to the ICL plant are 97.3 and 45.7 $\mu g/m^3$, respectively. Ambient background levels are not routinely determined for NO_2 over these short-term periods because the federal and state standards are written on an annual average basis (i.e., 100 $\mu g/m^3$). While it is recognized that short-term ambient background levels are likely to be higher than the annual average background concentration (5.4 $\mu g/m^3$), the site area is in attainment for NO_2. The combined impact (maximum incremental plus short-term background) should be much less than the threshold injury levels which are at least an order of magnitude higher than either of the incremental or background components of the total.

Dose-response curves reflecting injury potential due to exposure to particulate matter have not been generated because this material varies greatly in size and chemical composition. Most data pertain to the effects of settleable dusts. Total short-term and long-term TSP and PM-10 impacts are less than the significance level (see Section 5.6.1.3). Therefore, plant injury is not expected as a result of these fugitive dust-related impacts.

In comparison to other pollutants, relatively little research has been done regarding the effects of CO on vegetation. Available information indicates that a potential for injury does exist, but only at concentration levels far in excess of those estimated to occur from operations at the ICL plant. The 1-hour maximum incremental value is 25 times less than the corresponding significant impact level; the 8-hour value is 10 times lower than the 8-hour significance level (see Section 5.6.1.3). At these levels, damage to vegetation by CO emissions from the plant is not anticipated.

A more detailed discussion of potential effects on vegetation is found in Section 7.2 of the PSD permit application, Section 10.1.5 of this report.

5.6.2 MONITORING PROGRAMS

This section discusses the applicability of air quality-related monitoring programs to the proposed ICL facility. Emission limitations are established through the air quality permitting process. These limits represent the measures used to ensure that ambient standards will be met and that acceptable impacts will result from a proposed action. Compliance with these limitations is established through an emissions monitoring program. Compliance with ambient air quality standards represents a test of the effectiveness of those controls and the acceptability of the resulting impacts after the facility is operating. Similarly, air quality measurements in the pre-construction phase of a project represent a means for defining ambient conditions prior to a project's development.

5.6.2.1 Pre-Construction Ambient Air Quality Monitoring

Background air quality data, representative of ambient conditions in the site area, were available from nearby monitoring stations to perform the required air quality impact analyses for the proposed facility. Furthermore, results of a preliminary modeling analysis were used to demonstrate that incremental impacts were below the threshold levels that would require ambient monitoring to take place. The FDER has agreed that sufficient background data are available and has issued an exemption from any pre-construction monitoring requirements, with the condition that emissions used in the final modeling will not exceed those used in the preliminary modeling.

5.6.2.2 Post-Construction Ambient Air Quality Monitoring

The EPA's Ambient Monitoring Guidelines for PSD (EPA, 1987) indicate that the permit granting authority may require post-construction air quality monitoring, if:

- The proposed facility is a major source for the purposes of new source review
- There is an apparent threat to the ambient air quality standards
- The proposed source impact is uncertain or unknown (e.g., the source is located in complex terrain or in the presence of fugitive emissions, or has uncertain source or emission characteristics)
- There is a potential adverse impact on a Class I PSD area.

There are no plans to establish a post-construction ambient air quality monitoring program for the ICL plant. This rationale is discussed in the following subsections in the context of these four potential areas of concern to EPA.

Major Source Concern

The proposed ICL plant is a major stationary source subject to PSD and new source review. However, the implementation of BACT, under the PSD program, will substantially mitigate emissions.

Threat to Ambient Air Quality Standards

The EPA considers the ambient air quality standards to be threatened if the impacts due to the proposed source are projected to be equal to or greater than 90 percent of the ambient standards when the source becomes operational. The

ICL site is located in an attainment area for all criteria air pollutants. Representative background monitoring data for the site area corroborate this designation and indicate that ambient conditions are well below the corresponding standards (see Section 5.6.1.5).

The results in Section 5.6.1.6 indicate that maximum incremental impacts for particulates and CO are well below the corresponding significant impact levels. Although maximum incremental SO_2 and NO_2 concentrations are above the significant impact levels, total impacts (which include the effects of other nearby sources of these emissions and measured background levels) are well below the corresponding NAAQS and FAAQS. Therefore, it is reasonable to conclude that emissions from the proposed facility pose no threat of exceeding either the ambient standards or available PSD increment levels.

Uncertainty of Emissions Characteristics

Emissions from the main and auxiliary boilers represent well-defined point sources based on known fuel-firing scenarios and vendor design specifications. Furthermore, emissions will be controlled both through the application of BACT. Fugitive emissions are not expected to be a major concern and will be controlled both through the application of traditional mitigation measures and non-traditional methods in that the material handling systems will be totally enclosed and vented through fabric filters. The dispersion model used to estimate impacts from these sources incorporates EPA-approved algorithms to account for the various characteristics of these releases. Therefore, it may be concluded that the emissions and resulting estimated impacts can be readily quantified using applicable regulatory guidance, with a reasonable degree of certainty.

Impact on Class I PSD Areas

The closest Class I PSD area to the ICL site is the Everglades National Park, about 140 km away. Given the distance from the proposed source, neither significant incremental air quality impacts nor unacceptable impairment to visibility is expected.

5.6.2.3 Air Emissions Monitoring

The proposed facility is subject to the New Source Performance Standards codified at 40 CFR Part 60, Subpart Da (Standards of Performance for Electric Utility Steam Generating Units). The Florida Air Pollution Rules for new sources (at F.A.C. 17-2.660) adopts Subpart Da by reference.

In accordance with these requirements, a continuous emissions monitoring system (CEMS) will be installed, calibrated, maintained, and operated for measuring opacity of visible emissions and SO_2 and NO_2 emissions discharged to the atmosphere. A CEMS will also be provided to measure the oxygen or carbon monoxide content of the flue gases.

Initial performance tests will be conducted after plant startup and testing in accordance with Florida Air Pollution Rule 17-2.700 F.A.C. for those pollutants for which a BACT analysis is required. Compliance determination test methods and procedures applicable to the ICL emissions monitoring program are specified in F.A.C. 17-2.700 (6), and by reference, where appropriate, in Section 60.48a of Subpart Da and Appendix A to 40 CFR Part 60.

5.7 NOISE

Noise levels have been calculated that could be expected along the perimeter of the site and at the nearest residence due to the operations of the Indiantown Cogeneration, L.P. (ICL) plant. The locations that were selected for impact assessment are shown on Figure 5.7.0-1. Locations B, C, and D were selected to be representative of noise levels at the plant boundary that are closest to the sources of greatest noise emissions. Locations A and R are considered to be representative of noise levels which would be expected to occur at the nearest residences.

Modeling of the noise impacts was performed using a spreadsheet model based on the Edison Electric Institute publication, "Electric Power Plant Environmental Noise Guide" (Vol. 1, 2nd edition, 1984). This model was used to predict noise levels at each of these locations using typical noise levels and spectra for each of the main sources of noise emissions. Ground sound absorption effects (draft ISO standard) were accounted for in assessing impacts from all low elevation sources. This accounts for the soft absorptive fields between the ICL plant and noise receptors.

There are no state or local noise regulations for the Indiantown area. Therefore, the EPA guideline (EPA, 1974) recommended to protect public health and welfare for outdoor activity in residential areas and farms with a margin of safety was used. This noise level, a day/night weighted average (Ldn) of 55 dBA, represents the sound energy averaged over a 24-hour period with a 10 dB nighttime weighting to account for the difference in noise perception during the nighttime hours as compared to the daytime hours. An Ldn of 55 dBA translates into a continuous 24-hour noise level of 49 dBA that would be allowed from the power plant from all noise sources that normally operate at the plant.

The 12 major sources of noise within the ICL plant are listed in Table 5.7.0-1. Each was analyzed to determine their individual contributions to the total noise impact

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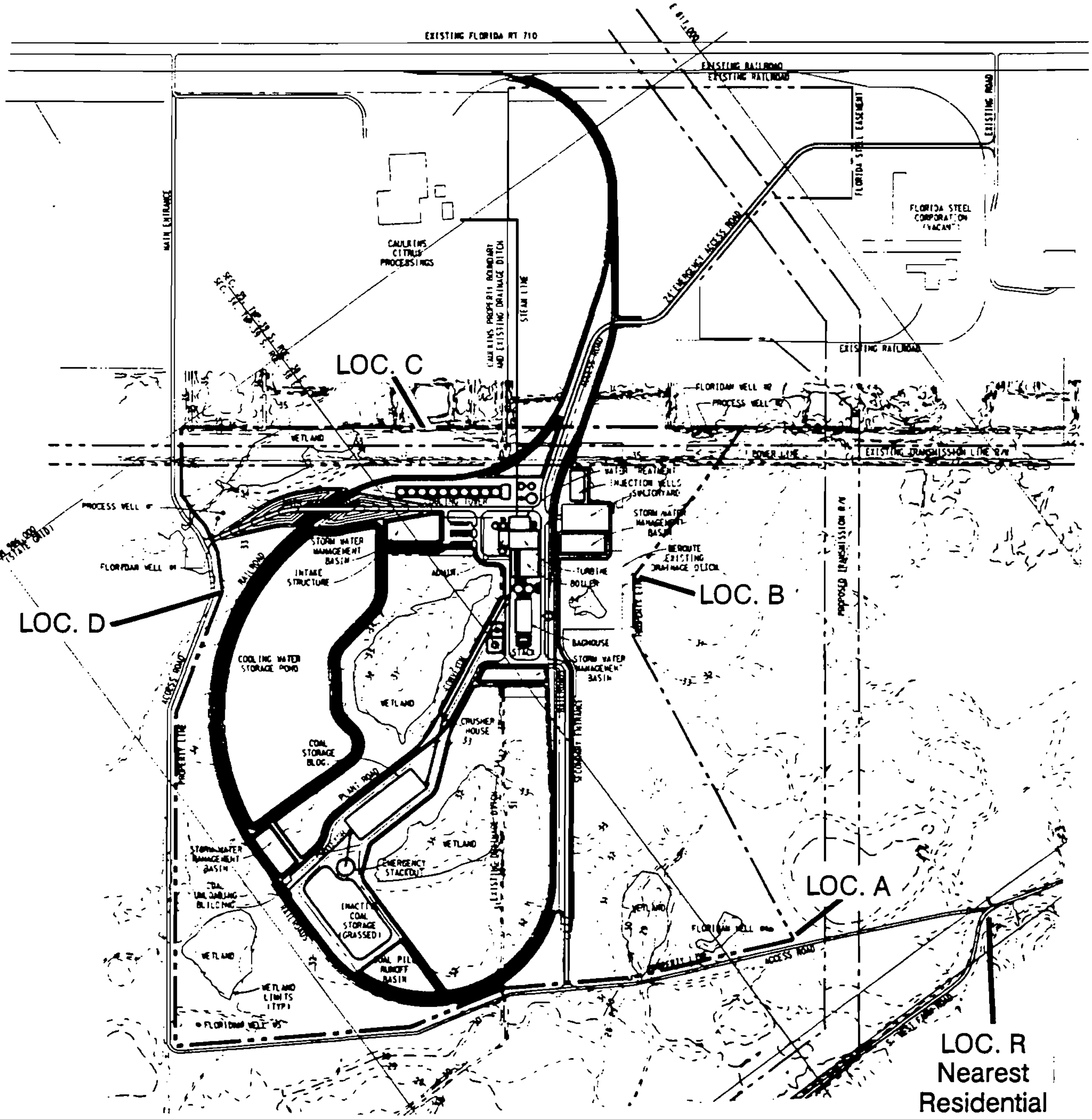

Figure 5.7.0-1.

PLOT PLAN OF SITE SHOWING NOISE EMISSION ANALYSIS LOCATIONS

Source: Hessler and Associates, 1990

INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

Table 5.7.0-1
MAJOR SOURCES OF NOISE WITHIN THE ICL PLANT

Induced Draft Fan Stack Outlet
Induced Draft Fan Ducting
Induced Draft Fan Housing
Forced Draft Inlet Opening
Forced Draft Fan ducting
Forced Draft Fan Housing
Cooling Towers
Main Boiler
Main Transformer
Coal Crusher
Steam Turbine Generator
Outdoor Fan Motors
Coal Unloader
Train

Source: Bechtel, 1990

at each of the receptors. The results of the analysis are presented in Table 5.7.0-2 where the total impact at each receptor is listed, as well as the individual contributions from each of the sources. The impacts of the 12 major noise sources are ranked by magnitude of effect for each receptor on this table. Additionally, the octave band frequency analysis for each source is presented on this table.

The need for mitigation of any sources of emissions is determined from the sum of the contributions of all sources for any receptor and comparing this value to the Ldn of 55 dBA. The individual sources that need to be mitigated are then determined from the relative ranking of their contributions to the total impact at the receptor in question. The type of mitigation and the amount of noise level reduction that is achievable for each source is assessed through an analysis of the octave band frequency distribution and the height of emission of each source. Thus, at receptors A and R, which are representative of impacts that could be expected at the nearest residences, it was determined that noise abatement measures would be required for the ID fans and the FD inlets because the total impact exceeded the Ldn of 55 dBA. The required silencer insertion losses for the ID fan and FD inlet silencers were calculated for use in the analysis.

The plant is designed with extensive noise abatement measures to limit noise emissions at location R, the closest residence, to a level of 42 dBA (41.9 dBA, Table 5.7.0-2), and 44.6 dBA at Location A. This level is 7 dBA below the federal EPA guidelines of 49 dBA for 24-hour per day plant operation.

The designed-in margin of 7 dBA is based on measurements of the existing background sound levels. These measurements were found to range from a low of 34 dBA during early morning, calm and still wind conditions, to a more typical level range of 38 to 42 dBA. This range is typical of those found in rural and very quite suburban residential areas.

Table 5.7.0-2

SUMMARY OF SOURCES AND IMPACTS AT RECEPTORS A THROUGH R

DESCRIPTOR		OCTAVE BAND CENTER FREQUENCY, HZ 31.5	63	125	250	500	1000	2000	4000	8000	OVERALL 'AWTD
SUMMARY OF SOURCES AT POSITION A (RESIDENTIAL DIRECTION)											
SOURCE DESCRIPTION:	NO.										
COOLING TOWERS	7	47	50	43	38	36	33	25	5	-68	37.8
OUTDOOR FAN MOTORS	12	36	38	30	29	31	33	30	15	-38	35.9
COAL CHRUSHER (1)	10	50	48	39	34	32	31	26	10	-45	35.3
STEAM TURBINE GENERATOR	11	45	51	43	35	32	29	23	0	-61	34.9
MAIN BOILER	8	51	50	39	31	31	30	25	11	-43	34.2
FD INLET OPNG.	4	50	51	41	34	28	27	25	24	-33	34.0
ID FAN STACK OUTLET	1	57	52	42	33	29	26	25	18	-34	33.8
FD FAN HOUSING	6	49	46	43	37	27	26	18	-1	-59	33.1
ID FAN HOUSING	3	52	46	40	33	20	20	13	-3	-56	28.9
MAIN TRANSFORMER	9	34	40	32	26	28	23	15	-4	-64	28.2
ID FAN DUCTING	2	43	39	35	27	17	16	9	-6	-59	23.7
FD FAN DUCTING	5	42	38	33	26	15	15	7	-10	-69	22.2
TOTAL Lp ALL SOURCES:		61	59	51	44	41	39	35	26	0	44.5
SUMMARY OF SOURCES AT POSITION B											
SOURCE DESCRIPTION:	NO.										
FD INLET OPNG.	4	62	63	53	47	41	41	42	51	31	53.1
OUTDOOR FAN MOTORS	12	47	49	46	43	45	47	47	41	21	51.8
MAIN BOILER	8	65	64	56	46	46	47	45	42	31	51.8
STEAM TURBINE GENERATOR	11	59	65	60	50	48	46	43	31	12	51.7
COOLING TOWERS	7	56	59	59	55	50	43	37	26	-7	51.4
MAIN TRANSFORMER	9	51	57	53	45	47	44	38	30	10	48.3
FD FAN HOUSING	6	61	58	59	50	42	41	36	27	6	47.9
ID FAN STACK OUTLET	1	66	61	51	43	39	36	37	38	17	45.1
COAL CHRUSHER (1)	10	57	55	48	41	40	40	36	25	-10	44.0
ID FAN HOUSING	3	62	56	54	45	33	34	29	21	0	41.9
FD FAN DUCTING	5	54	50	49	39	30	30	26	18	-2	37.2
ID FAN DUCTING	2	53	49	48	38	29	29	25	17	-4	36.3
TOTAL Lp ALL SOURCES:		72	71	66	59	55	54	51	52	34	60.0
SUMMARY OF SOURCES AT POSITION C											
SOURCE DESCRIPTION:	NO.										
COOLING TOWERS	7	71	74	71	65	64	63	60	56	42	67.7
STEAM TURBINE GENERATOR	11	59	65	59	50	47	46	42	31	10	51.1
MAIN BOILER	8	62	61	53	43	43	44	41	37	22	48.2
FD FAN HOUSING	6	56	51	54	50	39	36	30	19	-7	44.5
FD INLET OPNG.	4	57	56	45	39	33	33	34	41	16	43.8
MAIN TRANSFORMER	9	47	53	48	40	42	39	33	24	1	43.7
OUTDOOR FAN MOTORS	12	42	44	37	35	36	38	36	27	-5	41.8
COAL CHRUSHER (1)	10	55	53	46	39	38	37	34	21	-20	41.7
ID FAN STACK OUTLET	1	61	56	46	38	34	31	31	29	-2	39.0
ID FAN HOUSING	3	57	51	48	39	27	27	22	12	-20	35.9
FD FAN DUCTING	5	49	43	44	39	27	25	20	11	-14	33.7
ID FAN DUCTING	2	48	44	42	33	23	24	18	8	-24	30.8
TOTAL Lp ALL SOURCES:		73	75	72	65	65	63	60	56	42	67.9
SUMMARY OF SOURCES AT POSITION D											
SOURCE DESCRIPTION:	NO.										
COOLING TOWERS	7	56	59	59	56	52	47	41	31	-3	53.5
COAL CHRUSHER (1)	10	57	55	54	49	47	43	39	28	-9	48.4
STEAM TURBINE GENERATOR	11	51	57	55	50	45	40	35	18	-21	47.2
OUTDOOR FAN MOTORS	12	39	41	43	43	42	41	38	27	-13	45.1
MAIN BOILER	8	56	55	50	43	41	38	34	26	-7	43.7
FD INLET OPNG.	4	54	55	45	38	33	32	31	35	-5	40.1
FD FAN HOUSING	6	53	50	49	42	33	32	25	10	-30	38.5
ID FAN STACK OUTLET	1	59	54	44	36	32	29	29	25	-15	36.7
MAIN TRANSFORMER	9	41	47	40	33	35	31	24	11	-29	35.9
ID FAN HOUSING	3	55	49	44	36	24	24	18	6	-34	32.7
FD FAN DUCTING	5	46	42	39	31	21	21	15	2	-37	27.9
ID FAN DUCTING	2	46	42	39	31	21	21	15	2	-37	27.8
TOTAL Lp ALL SOURCES:		65	64	62	58	54	50	46	38	0	56.3
SUMMARY OF SOURCES AT POSITION R (NEAREST RESIDENTIAL LOCATION)											
SOURCE DESCRIPTION:	NO.										
COOLING TOWERS	7	46	49	41	36	34	31	22	-1	-85	35.7
STEAM TURBINE GENERATOR	11	43	49	41	33	30	27	19	-6	-78	32.6
MAIN BOILER	8	50	49	38	30	29	28	22	6	-57	32.3
OUTDOOR FAN MOTORS	12	34	36	27	27	28	29	25	7	-60	32.2
FD INLET OPNG.	4	49	49	39	33	26	24	22	18	-49	31.6
ID FAN STACK OUTLET	1	54	49	40	31	27	23	22	12	-54	31.3
COAL CHRUSHER (1)	10	48	45	36	30	29	27	21	0	-73	31.2
FD FAN HOUSING	6	47	44	41	34	25	23	14	-9	-81	30.3
MAIN TRANSFORMER	9	35	41	32	27	28	23	14	-8	-82	28.6
ID FAN HOUSING	3	50	44	37	30	17	17	9	-11	-77	26.1
ID FAN DUCTING	2	41	37	31	24	14	13	5	0	0	20.7
FD FAN DUCTING	5	40	36	31	23	13	12	4	-17	-88	19.7
TOTAL Lp ALL SOURCES:		59	57	49	42	39	37	31	20	0	41.9

(1) DAY TIME ONLY. TOTAL Lp IS APPROXIMATELY 1/2 dBA QUIETER AT NIGHT W/O CHRUSHER

Source: Hessler, 1990

Subjectively, the ICL plant sound will be detectable and audible only during calm and still wind conditions. Such conditions occur about 5 percent of the time. At other times, the plant will be inaudible, as the plant sound is not greatly above the measured normal ambient sounds consisting of far-off road sources, rustling grasses, trees, bird, and insect sounds.

Based on the above analysis and discussion, ICL plant operational sound is not expected to have any impact on adjacent residences located on South West Farm Road.

The estimated noise levels at location R due to the ICL plant emissions are compared to the measured ambient levels at the site on Figure 5.7.0-2. The abatement measures discussed above are applied to the major sources of noise that impact this receptor. These abatement measures were mainly directed towards reducing the peaks that occurred in the 150 to 250 Hz octave band center frequencies.

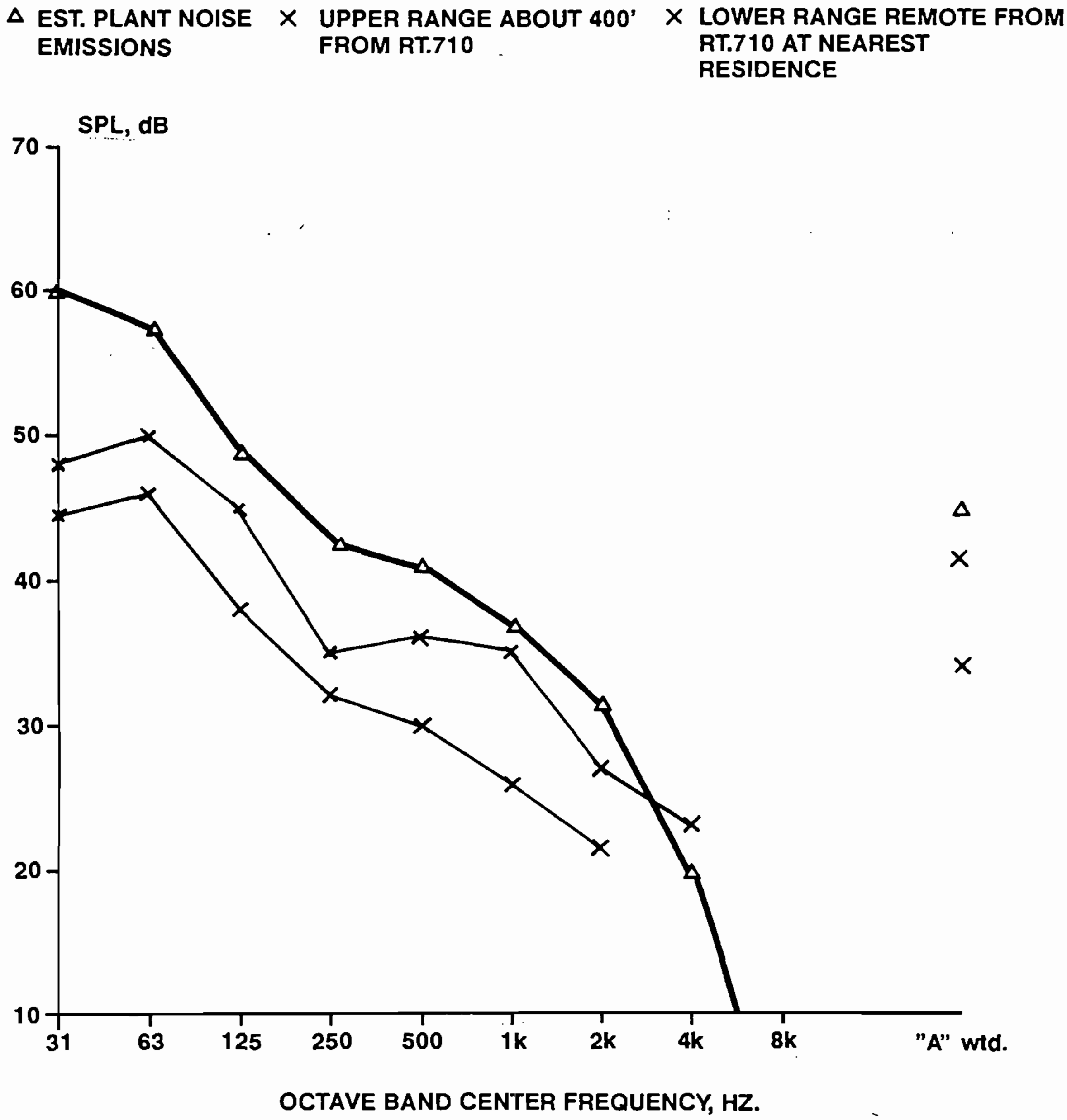

Figure 5.7.0-2.

ESTIMATED NOISE EMISSIONS AT POSITION R COMPARED TO AREA RESIDENTIAL (L90) AMBIENT RANGE

Source: Hessler and Associates, 1990

INDIANTOWN COGENERATION PROJECT

Indiantown Cogeneration, L.P.

5.8 CHANGES IN NONAQUATIC SPECIES POPULATIONS

5.8.1 IMPACTS

The flatwoods vegetation and wildlife habitat situated on the ICL site are targeted for removal or modification, except for those areas set aside for upland and wetland preservation or future use (see Section 4.4). It is the biota associated with areas that are to remain on or near the project site that will be discussed in the following paragraphs in terms of potential long-term changes in species populations resulting from air emissions from the project operation.

The effects of long-term (chronic) exposures to concentrations of SO_2, NO_x, O_3, a mixture of SO_2-NO_x, a mixture of SO_2-O_3, CO_2, VOC, trace elements, and fugitive dust below those concentrations that result in acute injury symptoms, is not well documented in the literature. However, the literature does report that chronic injury symptoms do occur when plants are exposed to concentrations below injury threshold levels. Even if chronic injury symptoms were manifested by site vegetation, it is not anticipated that the injury will be severe enough to result in changes in species diversity and composition.

Factors, such as water availability, light, and soil nutrients, would tend to have a greater effect on species diversity and composition than exposure to low levels of air contaminants.

5.8.2 MONITORING

It is not expected that monitoring of site nonaquatic species will be necessary.

5.9 OTHER PLANT OPERATION EFFECTS

Traffic impacts resulting from the operation of the ICL project are discussed in Section 7.0, and a complete traffic analysis is located in Section 10.0. A beneficial effect from the operation of the plant is the supplying of process steam to Caulkins Citrus and the availability of process steam to any operating or future requirements by light industry. All other effects resulting from the operation of the ICL plant are discussed within the appropriate sections of the SCA.

5.10 ARCHAEOLOGICAL SITES

As previously discussed in Section 2.2.6, and as discussed in detail in Section 10.8, no archaeological or historic resources were previously listed in the location of the Indiantown Cogeneration, L.P. (ICL) project site. In addition, no archaeological or historic resources eligible for inclusion in the *National Register of Historic Places* were found during research and field assessment. Therefore, activities involved with the operation of the plant should have no impact on significant archaeological or historic resources.

Should post-construction activities cause the discovery of unanticipated archaeological materials, those activities which potentially would disturb such materials will be postponed until a professional archaeologist can evaluate their potential significance. In the event the materials are believed to be significant, the State Historic Preservation Office (SHPO) will be contacted to identify appropriate measures.

5.11 RESOURCES COMMITTED

5.11.1 WATER RESOURCES

The ICL plant will utilize surface water from Taylor Creek/Nubbin Slough (TC/NS) as its primary water source. This will have the benefit of reducing the amount of phosphorous currently being discharged to Lake Okeechobee. The backup source of water will be the Floridan aquifer, which has a high TDS level. This will be used only during extended periods of drought when TC/NS water is unavailable.

No water will be withdrawn from the surficial aquifer, a source of potable water for residences. No wastewater will be discharged to a surface body of water. Wastewater will be reused within the plant to the extent practicable and the remainder will be discharged to the Boulder Zone of the Floridan aquifer.

5.11.2 BIOLOGICAL RESOURCES

Except for the flatwoods eliminated during construction, operation of the plant will not require the commitment of additional wildlife habitat or other terrestrial or wetland vegetation, and will have no measurable effect on wildlife species populations, including threatened or endangered species. The ICL plant emissions into the air are also not expected to have a measurable effect on the growth and productivity of surrounding vegetation, including agricultural crops.

5.11.3 ECONOMIC AND CULTURAL RESOURCES

Economic resources committed to the ICL plant are expected to include wages and labor, financial investment, and the displacement of other economic uses of the site. Specific characterization of the operational workforce is contained in Section 7.2, which describes a projected permanent workforce of 80 persons. These 80 positions represent a permanent commitment for the duration of the project, regardless of the tenure of individuals employed at the ICL plant. Therefore, the 80 individuals employed at the ICL project represent a permanent commitment of a workforce which will not be available for employment elsewhere.

Economic commitments are also discussed in detail in Section 7.0. As with labor, the financial investment represents an irreversible commitment which will not be available for other uses as long as the ICL plant remains in operation. Additional tax revenues and impact fees generated as a result of the project, as discussed in detail in Section 7.1.2, are expected to be sufficient to support additional public services and infrastructure required for the operation of the ICL plant. A detailed long-term, benefit-cost analysis is provided in Section 7.2. The need for commitment of additional governmental financial resources required to fund public services beyond those funded by the additional tax revenues and impact fees is not expected.

The displacement of current economic uses due to a change in land use are predicted to be relatively insignificant because the site is currently under-utilized for limited grazing purposes. Many alternative sites are available in the immediate area and within the region, and therefore, the loss of these grazing lands should not represent a significant impact on agricultural land uses in the area. There are no other existing or planned economic uses of the site.

Because no cultural resources are expected to be impacted on the project site, no commitment of archaeological resources is anticipated.

5.12 VARIANCES

At the present time, there are no variances from applicable standards of the state certification proceedings.

REFERENCES

Section 5.1

Electric Power Research Institute (EPRI). User's Manual Cooling-Tower-Plume Prediction Code. Argonne National Laboratory. EPRI CS-3403-CCM.

Moon, M.L. (Editor). Overview of the Chalk Point Cooling Tower Project. The Johns Hopkins University, Laurel, Maryland.

Mulchi, C.L., D.C. Wolf; and J.A. Armbruster. Cooling Tower Effects on Crops and Soils. Chalk Point Plant Cooling Tower Project, FY'78 Final Report, Post Operational Report No. 3, Water Resources Center, University of Maryland, Maryland Power Plant Siting Program PPSP-CPCTP-23, WRRC Special Report No. 11. July, 1978.

Section 5.3.1

Ardaman & Associates, Inc., October 17, 1989, Remedial Investigation Report, Phase II, Florida Steel Corporation, Indiantown Mill Site, Martin County, Florida, Volume I.

CH2M Hill. Technical Memorandum No. 3, SCA Section 2.3.2.1, Subsurface Hydrologic Data, Indiantown Cogeneration, Facility, Indiantown, Florida. October 30, 1990.

McWhorter, D.B.; Sunada, D.K. Ground-Water Hydrology and Hydraulics, Water Resources Publication, Fort Collins, CO. 1977

South Florida Water Management District. Draft Interim Surface Water Improvement and Managements (SWIM) Plan for Lake Okeechobee, Part I:Water Quality. 1989.

South Florida Water Management District. Martin County Water Resource Assessment, S. Trost and D. Nealson Editors, Resource Planning Department. 1987.

U.S. Department of Agriculture Soil Conservation Service, Soil Survey, Martin County Area, Florida. 1981.

U.S. Department of Agriculture Soil Conservation Service, Soil Survey, Okeechobee County, Florida. 1971.

Section 5.4.1

Martin County Comprehensive Growth Management Plan (Adopted). Martin County Growth Management Department. 1990.

Section 5.6.1

U.S. Environmental Protection Agency. Industrial Source Complex (ISC) Dispersion Model User's Guide-Second Edition (Revised), EPA-450/4-88-002a, Office of Air Quality Planning and Standards, Research Triangle Park, NC. December, 1987.

U.S. Environmental Protection Agency. Workbook for Visual Plume Impact Screening and Analysis, EPA-450/4-88-015, Office of Air Quality Planning Standards, Research Triangle Park, NC. September, 1988.

Section 5.6.2

U.S. Environmental Protection Agency, Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87-007, Office of Air Quality Planning and Standards, Research Triangle Park, NC. May, 1987.

Section 5.7

U.S. Environmental Protection Agency, Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety. EPA 550/9-74-004. 1974.

6.0 LINEAR FACILITIES

6.1 TRANSMISSION LINE

There will be no transmission line constructed since the connection will be to the FPL 230 kV line that traverses the northern boundary of the site. Therefore, Section 6.1 is not applicable to the ICL project.

QUESTION 36

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

Tables 2.3.7-6, 3.4.4-1 and 1.1 (Section 10.1.5) appear to be incomplete. They exclude some of the regulated pollutants which require BACT review (fluoride and sulfuric acid mist). Please provide air emission information and discussion of controls utilized for all sources.

RESPONSE

Emissions rates for fluorides and sulfuric acid mist for the PC and auxiliary boiler are presented below:

Pollutant	PC Boiler		Auxiliary Boiler*	
	lb/hr	ton/yr	lb/hr	ton/yr
Total Fluorides	7.26	22.26	1.4×10^{-5}	7.3×10^{-6}
Sulfuric Acid Mist	1.45	6.35	0.26	0.65

*5,000 hours per year on natural gas

Since fluoride will be emitted as hydrofluoric acid, the evaluation of controls for this pollutant, as well as controls for sulfuric acid mist, was presented along with the review of the controls of other acid gases in Section 3.4.3.2 and in greater detail in the BACT analysis, Section 10.4. As demonstrated, the use of lime spray drying is concluded representative of BACT for acid gases (including HF and H_2SO_4) for the PC boiler, and the use of low sulfur fuel is concluded representative of BACT for acid gases for the auxiliary boiler.

QUESTION 37

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

Also, in accordance with EPA policy developments all toxic non-regulated pollutants emitted by the proposed facility need to be addressed with respect to the proposed and alternative control technologies. The pollutants are identified in the publications entitled "Compiling Air Toxic Emission Inventories", EPA 450/4-96-010 and "Control Technologies for Hazardous Air Pollutants", EPA 625/6-86-014. In accordance with those publications and the fuel analyses presented in the application, the following pollutants need to be addressed: Antimony, barium, cadmium, chromium, cobalt, copper, vanadium, formaldehyde, manganese, nickel, zinc, polycyclic organic matter, phosphorus, phenol, chlorine (hydrogen chloride), pyridine, acetaldehyde, acetic acid, and dioxin.

RESPONSE

The table on the next page summarizes the information contained in the two cited references relative to the disposition in combustion device flue gas of the subject air toxic compounds.

To our knowledge, neither PC boilers nor No. 2 fuel oil-fired boilers are sources of acetaldehyde or acetic acid emissions. These compounds are not included on the lists of potential hazardous air pollutants in the cited references (EPA 625/6-86-014 "Control Technologies for Hazardous Air Pollutants" Table 2-11 and EPA 450/4-86-010 "Compiling Air Toxics Inventories" Table F-17). Additionally, no emission factors for these compounds from these sources are contained in the latest EPA publication on the subject (EPA 450/2-88-006a "Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxic Compounds and Sources").

	PC Boiler		Auxiliary Boiler	
	Vapor	Particulate	Vapor	Particulate
ORGANIC COMPOUNDS				
Formaldehyde	X		X	
Phenol	X			
POM		X		X
Pyridine	X			
INORGANIC COMPOUNDS				
Antimony	X	X		X
Barium		X		X
Cadmium	X	X		X
Chromium	X	X		X
Cobalt		X		X
Copper		X		X
HCl	X		X	
Manganese		X		X
Nickel		X		X
Phosphorous		X		
Vanadium				X
Zinc		X		X
Sources: EPA 625/6-86-014 "Control Technologies for Hazardous Air Pollutants" Table 2-11; EPA 450/4-86-010 "Compiling Air Toxics Inventories" Table F-17				

Control of emissions of acid gases, such as hydrogen chloride, has been addressed in the SCA application in Section 3.4.3.2 (Sulfur Dioxide and Acid Gases) and in greater detail in the BACT Analysis Section 10.6.4. Specific mention of HCl was inadvertently omitted from these discussions; however, the use of a lime spray dryer is considered representative of the most stringent control of all acid gases, including HCl.

As described in the two cited references, the majority of the metals (including Antimony, barium, cadmium, chromium, cobalt, copper, vanadium, manganese, nickel, phosphorus and zinc), as well as polycyclic organic matter (POM) will be emitted from the proposed facility either as, or condensed on, particulate matter. In SCA Application Section 3.4.3.3 and BACT Analysis Section 10.8, control of particulate matter is considered by the EPA to be representative of control of trace metals and POM since these compounds are volatized in the combustion section of the boiler and tend to condense onto fine solid particles in the flue gas. Thus, as for the regulated trace metals arsenic and beryllium, stringent control of particulate matter is concluded to be sufficient for control of non-regulated trace metals and POM as well.

For the PC boiler, fabric filtration is considered more stringent that electrostatic precipitation for fine particles. Although the use of GORE-TEX bags may result in a decrease in annual PM emissions, and consequently lower emissions of trace metals and POM, the extremely small difference in emission reductions potential means that the emission level achieved using these bags is economically infeasible and thus unrepresentative of BACT.

For the auxiliary boiler, use of low ash fuel is concluded to be representative of BACT since the alternative, electrostatic precipitation, results in a cost effectiveness of over $130,000/ton removed. Additionally, trace metals and POM tend to condense onto the smaller particles, due to the greater surface-to-volume of small particles compared to large particles. Since an ESP is not as effective at collecting small particles as large particles, it would be inappropriate to use an ESP on the auxiliary boiler specifically to achieve lower non-regulated trace metals and POM emissions that using low ash fuel.

As mentioned, to our knowledge no data exist to characterize the magnitude of emissions of the non-regulated compounds cited (formaldehyde, phenol, pyridine, acetaldehyde, and acetic acid) from PC and No. 2 fuel oil-fired boilers. However, control of emissions of volatile organic compounds (VOCs) is discussed in Section 3.4.3.4 of the SCA Application and Section 10.6.5. No alternatives which are more stringent than the proposed combustion controls have been demonstrated to be technically feasible for control of VOCs, including non-regulated organic compounds. Therefore, although these non-regulated compounds are not specifically mentioned in the previously submitted SCA and PSD Applications, BACT for VOC is concluded to be representative of the most stringent control for these non-regulated compounds as well.

A great deal of attention has been focused in recent years on polychlorinated dibenzodioxin (PCDD) and polychlorinated dibenxzofuran (PCDF) emissions from a variety of combustion sources, particularly sources combusting materials containing known precursors to either PCDD or PCDF. Such precursors include chlorinated phenols and benzenes. Although these precursors are not known to exist naturally in coal, it is established that coal contains relatively high levels of inorganic chloride. However, there is no evidence to support that the integral precursors for PCDD or PCDF formation are emitted or that non-chlorinated PAH homologues provide a hydrocarbon foundation for such formations during the burning of coal.

Furthermore, the US EPA National Dioxin Strategy did not identify coal-fired power plants as likely combustion sources of PCDD or PCDF. In addition, these sources were eliminated as possible sources of 2,3,7,8-TCDD by a number of studies reported in the scientific literature (Kimble and Gross, 1980; Junk and Richard, 1981). Haile et al (1984) reported emission results from several utility coal plants where PCDD and PCDF homologues were not identified in any sample taken from flue gas outlet, fly ash emissions, and coal feed. Harless and Lewis (1982) and DeRoos and Bjorseth (1979) also tested fly ash emissions and found the samples to contain nondetectable levels of TCDD.

QUESTION 38

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

Table 1.1 (Section 10.1.5) lists the cooling tower as an emission source. Please provide emission estimates and controls for the cooling towers.

RESPONSE

The stated Table 1.1 (Section 10.1.5) of the BACT document provides emissions from the main PC boiler and the auxiliary boiler only. The cooling tower is listed as an Indiantown Cogeneration emission source in Table 1 of the PSD Permit Application Forms (Application To Operate/Construct Air Pollution Sources). Cooling tower emissions are in the form of water vapor salt drifts. Drift emissions are minimized by using a state-of-the-art drift eliminator with a design drift loss rate of 0.002 percent of the total circulating water flow passing through the cooling tower. In addition, a side stream softener is employed to remove suspended solids within the circulating water; this in turn acts to minimize suspended solid emissions from the tower. For all practical purposes, all the precipitates and suspended solids settle to the bottom of the clarifier as sludge.

The estimated drift emission from the proposed ICP cooling tower is 5.3 gpm. The Total Dissolved Solids (TDS) concentration within the drift was estimated to be 2,830 mg/l with chloride constituting 38.2 percent of the TDS.

As the moist plume exits the cooling tower, it rises, expands, and cools by mixing with the cooler and drier ambient air. As the vapor plume cools, condensation occurs and the plume becomes visible. From the drift plume, droplets precipitate out and are deposited to the ground. These droplets evaporate during their fall and may eventually result in salt particles being deposited on the ground. It should be noted that large droplets in the plume will deposit closer to the tower than the small droplets. As shown on Table FDER38-1 for the ICP tower, the majority of these drifts fall within 100 meters of the cooling tower.

Environmental impacts due to operation of the proposed cooling tower were evaluated using the Seasonal/Annual Cooling Tower Plume Impact model (SACTI), which is sponsored by Electric Power Research Institute (EPRI, 1984). This numerical model is an extension of an earlier model evaluation study carried out by Argonne National Laboratory. The SACTI model uses cooling tower effluent release parameters to determine a series of atmospheric conditions affecting plume dispersion and deposition. The model calculates: salt deposition rate from the plume drift; visible plume length/height; and fogging/icing for the determined meteorological conditions. The impact assessment of the cooling tower emissions is presented in Section 7.3.3 of the PSD Permit Application in Section 10.1.5 of the SCA. Additional discussion of impacts from salt deposition is presented in response to Martin County Question 3.

Table FDER38-1

********************************* PLUME CHLORIDE DEPOSITION TABLE (G./(M.**2-10 DAYS)) *********************************

INDIANTOWN, 1982-86 WEST PALM BEACH MET. DATA (LMDCT, 10 CYCLES)

SEASON=ANNUAL

DISTANCE FROM TOWER (M)	WIND FROM N / PLUME HEADED S	NNE / SSW	NE / SW	ENE / WSW	E / W	ESE / WNW	SE / NW	SSE / NNW	S / N	SSW / NNE	SW / NE	WSW / ENE	W / E	WNW / ESE	NW / SE	NNW / SSE	AVG / AVG
100	1.849	1.214	2.671	3.846	7.632	4.614	4.873	2.485	2.965	1.109	1.251	1.037	1.634	1.417	1.837	1.500	2.621
150	0.270	0.198	0.414	0.525	1.018	0.474	0.498	0.353	0.456	0.237	0.262	0.161	0.260	0.166	0.219	0.233	0.359
200	0.078	0.079	0.168	0.187	0.350	0.177	0.186	0.106	0.123	0.095	0.106	0.043	0.072	0.048	0.061	0.060	0.121
250	0.054	0.065	0.156	0.096	0.182	0.105	0.111	0.063	0.082	0.064	0.071	0.031	0.051	0.030	0.039	0.047	0.078
300	0.039	0.023	0.046	0.071	0.138	0.064	0.069	0.047	0.061	0.030	0.034	0.024	0.038	0.025	0.033	0.036	0.049
350	0.024	0.015	0.029	0.053	0.105	0.057	0.061	0.034	0.041	0.023	0.025	0.013	0.021	0.023	0.031	0.019	0.036
400	0.017	0.009	0.016	0.025	0.051	0.037	0.039	0.021	0.030	0.016	0.018	0.010	0.016	0.013	0.016	0.015	0.022
450	0.015	0.005	0.009	0.022	0.045	0.025	0.028	0.019	0.028	0.011	0.012	0.010	0.015	0.006	0.008	0.014	0.017
500	0.014	0.003	0.004	0.018	0.036	0.023	0.025	0.016	0.023	0.007	0.007	0.009	0.014	0.006	0.007	0.013	0.014
550	0.013	0.002	0.004	0.014	0.030	0.019	0.021	0.014	0.021	0.006	0.006	0.008	0.013	0.005	0.007	0.013	0.012
600	0.009	0.002	0.003	0.012	0.024	0.017	0.019	0.010	0.015	0.004	0.005	0.006	0.009	0.005	0.007	0.009	0.010
650	0.006	0.002	0.003	0.011	0.021	0.015	0.016	0.008	0.010	0.003	0.004	0.003	0.005	0.004	0.006	0.005	0.008
700	0.004	0.001	0.003	0.005	0.012	0.014	0.015	0.005	0.007	0.003	0.003	0.002	0.004	0.004	0.005	0.004	0.006
750	0.003	0.002	0.003	0.003	0.008	0.010	0.011	0.004	0.006	0.003	0.003	0.002	0.003	0.003	0.004	0.003	0.005
800	0.003	0.001	0.003	0.003	0.007	0.008	0.009	0.003	0.005	0.002	0.003	0.002	0.003	0.003	0.003	0.003	0.004
850	0.002	0.002	0.003	0.003	0.005	0.006	0.007	0.002	0.004	0.002	0.002	0.001	0.002	0.002	0.003	0.002	0.003
900	0.002	0.002	0.005	0.002	0.005	0.006	0.007	0.002	0.003	0.003	0.003	0.001	0.002	0.002	0.003	0.002	0.003
950	0.002	0.003	0.007	0.002	0.005	0.006	0.007	0.002	0.003	0.003	0.003	0.001	0.002	0.002	0.003	0.002	0.003
1000	0.002	0.003	0.008	0.002	0.004	0.006	0.006	0.002	0.003	0.003	0.003	0.001	0.002	0.002	0.003	0.002	0.003

************************************ PLUME CHLORIDE DEPOSITION TABLE (G./(M.**2-10 DAYS)) ************************************

INDIANTOWN, 1982-86 WEST PALM BEACH MET. DATA (LMDCT, 10 CYCLES)

SEASON=SPRING

DISTANCE FROM TOWER (M)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	AVG
PLUME HEADED	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	AVG
100	1.453	1.059	2.680	4.236	7.736	4.650	5.381	3.193	3.074	1.162	1.586	1.261	2.032	1.507	1.370	1.216	2.725
150	0.215	0.175	0.409	0.583	1.022	0.489	0.569	0.444	0.462	0.231	0.318	0.198	0.323	0.176	0.161	0.188	0.373
200	0.061	0.070	0.164	0.208	0.351	0.182	0.211	0.139	0.127	0.096	0.129	0.054	0.098	0.055	0.046	0.050	0.128
250	0.042	0.052	0.128	0.107	0.181	0.107	0.122	0.079	0.081	0.078	0.090	0.037	0.063	0.031	0.028	0.038	0.079
300	0.031	0.021	0.048	0.079	0.137	0.064	0.075	0.058	0.062	0.028	0.040	0.029	0.046	0.025	0.023	0.028	0.050
350	0.018	0.014	0.030	0.059	0.106	0.057	0.066	0.044	0.043	0.021	0.029	0.017	0.027	0.023	0.022	0.015	0.037
400	0.013	0.008	0.016	0.028	0.052	0.038	0.044	0.026	0.030	0.015	0.021	0.012	0.019	0.013	0.012	0.012	0.022
450	0.012	0.005	0.009	0.024	0.045	0.024	0.027	0.022	0.027	0.010	0.013	0.011	0.017	0.006	0.006	0.011	0.017
500	0.011	0.003	0.004	0.020	0.036	0.022	0.024	0.018	0.022	0.006	0.008	0.010	0.015	0.005	0.005	0.010	0.014
550	0.010	0.002	0.004	0.016	0.030	0.019	0.021	0.016	0.020	0.005	0.007	0.009	0.013	0.005	0.005	0.009	0.012
600	0.007	0.002	0.003	0.013	0.024	0.016	0.018	0.011	0.014	0.004	0.005	0.007	0.010	0.005	0.004	0.007	0.009
650	0.005	0.002	0.003	0.012	0.021	0.014	0.016	0.009	0.010	0.003	0.004	0.004	0.006	0.004	0.004	0.004	0.007
700	0.003	0.001	0.003	0.006	0.012	0.013	0.015	0.006	0.007	0.003	0.004	0.003	0.004	0.004	0.003	0.003	0.006
750	0.003	0.002	0.004	0.004	0.008	0.010	0.011	0.004	0.006	0.003	0.004	0.002	0.003	0.003	0.003	0.002	0.004
800	0.002	0.002	0.003	0.003	0.007	0.008	0.009	0.004	0.005	0.002	0.003	0.002	0.003	0.002	0.002	0.002	0.004
850	0.002	0.002	0.005	0.003	0.005	0.006	0.007	0.003	0.003	0.002	0.003	0.002	0.003	0.002	0.002	0.002	0.003
900	0.002	0.003	0.008	0.003	0.005	0.006	0.006	0.003	0.003	0.002	0.003	0.001	0.002	0.002	0.002	0.001	0.003
950	0.001	0.004	0.010	0.003	0.005	0.006	0.006	0.002	0.003	0.003	0.004	0.001	0.002	0.002	0.002	0.001	0.003
1000	0.001	0.005	0.012	0.002	0.004	0.005	0.006	0.002	0.002	0.003	0.004	0.001	0.002	0.002	0.002	0.001	0.003

********************************** PLUME CHLORIDE DEPOSITION TABLE (G./(M.**2-10 DAYS)) **********************************
INDIANTOWN, 1982-86 WEST PALM BEACH MET. DATA (LMDCT, 10 CYCLES)
SEASON=SUMMER

DISTANCE FROM TOWER (M)	WIND FROM N / PLUME HEADED S	NNE / SSW	NE / SW	ENE / WSW	E / W	ESE / WNW	SE / NW	SSE / NNW	S / N	SSW / NNE	SW / NE	WSW / ENE	W / E	WNW / ESE	NW / SE	NNW / SSE	AVG / AVG
100	1.129	0.588	1.527	2.056	5.759	7.019	7.566	2.801	3.947	1.404	1.452	1.084	1.447	0.928	0.901	0.621	2.514
150	0.183	0.106	0.246	0.267	0.728	0.700	0.726	0.409	0.627	0.316	0.318	0.168	0.231	0.097	0.094	0.104	0.332
200	0.048	0.042	0.099	0.090	0.240	0.260	0.269	0.115	0.163	0.120	0.124	0.042	0.058	0.028	0.029	0.024	0.109
250	0.037	0.026	0.065	0.048	0.130	0.152	0.162	0.075	0.113	0.074	0.076	0.032	0.045	0.019	0.020	0.020	0.068
300	0.025	0.013	0.030	0.036	0.099	0.097	0.107	0.054	0.082	0.041	0.041	0.024	0.032	0.016	0.016	0.015	0.046
350	0.015	0.010	0.021	0.027	0.075	0.084	0.092	0.038	0.056	0.031	0.032	0.014	0.019	0.014	0.015	0.008	0.034
400	0.013	0.006	0.012	0.014	0.038	0.051	0.054	0.026	0.043	0.021	0.023	0.011	0.016	0.007	0.008	0.008	0.022
450	0.012	0.004	0.007	0.012	0.032	0.038	0.044	0.024	0.041	0.014	0.014	0.010	0.015	0.005	0.006	0.007	0.018
500	0.011	0.002	0.004	0.010	0.028	0.034	0.039	0.020	0.033	0.009	0.009	0.009	0.013	0.004	0.005	0.006	0.015
550	0.010	0.002	0.004	0.008	0.023	0.029	0.033	0.018	0.031	0.007	0.008	0.009	0.012	0.004	0.005	0.006	0.013
600	0.007	0.001	0.003	0.007	0.019	0.026	0.029	0.013	0.021	0.006	0.006	0.006	0.009	0.004	0.004	0.004	0.010
650	0.004	0.001	0.002	0.006	0.016	0.022	0.024	0.009	0.014	0.004	0.004	0.004	0.005	0.003	0.004	0.002	0.008
700	0.003	0.001	0.002	0.003	0.009	0.020	0.023	0.006	0.010	0.004	0.004	0.003	0.004	0.003	0.003	0.002	0.006
750	0.003	0.001	0.003	0.002	0.006	0.015	0.018	0.005	0.009	0.004	0.004	0.002	0.003	0.002	0.003	0.002	0.005
800	0.002	0.001	0.003	0.002	0.006	0.012	0.015	0.004	0.007	0.003	0.003	0.002	0.003	0.002	0.002	0.002	0.004
850	0.002	0.001	0.004	0.002	0.005	0.009	0.011	0.003	0.004	0.003	0.003	0.001	0.002	0.002	0.002	0.001	0.003
900	0.001	0.002	0.005	0.002	0.004	0.009	0.011	0.002	0.004	0.004	0.004	0.001	0.002	0.002	0.002	0.001	0.003
950	0.001	0.002	0.007	0.001	0.004	0.009	0.011	0.002	0.004	0.004	0.004	0.001	0.002	0.002	0.002	0.001	0.004
1000	0.001	0.002	0.008	0.001	0.003	0.009	0.010	0.002	0.003	0.004	0.004	0.001	0.001	0.001	0.002	0.001	0.003

******************************** PLUME CHLORIDE DEPOSITION TABLE (G./(M.**2-10 DAYS)) ********************************

INDIANTOWN, 1982-86 WEST PALM BEACH MET. DATA (LMDCT, 10 CYCLES)

SEASON=FALL

DISTANCE FROM TOWER (M) — WIND FROM	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	AVG
PLUME HEADED	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	AVG
100	2.1982	2.4291	5.0386	6.6696	10.820	4.2887	2.9680	1.4805	1.7963	0.6963	0.7100	0.6729	0.9893	0.9529	1.5571	1.4074	2.7922
150	0.3112	0.3795	0.7724	0.8964	1.4159	0.4449	0.3075	0.2134	0.2795	0.1576	0.1644	0.1034	0.1554	0.1067	0.1841	0.2152	0.3817
200	0.0950	0.1523	0.3155	0.3223	0.4888	0.1685	0.1140	0.0623	0.0730	0.0615	0.0644	0.0267	0.0380	0.0305	0.0546	0.0560	0.1326
250	0.0614	0.1376	0.3473	0.1632	0.2521	0.1028	0.0704	0.0371	0.0519	0.0385	0.0434	0.0214	0.0299	0.0204	0.0339	0.0428	0.0908
300	0.0444	0.0410	0.0807	0.1222	0.1931	0.0604	0.0443	0.0278	0.0377	0.0205	0.0213	0.0154	0.0233	0.0173	0.0278	0.0326	0.0506
350	0.0284	0.0254	0.0476	0.0920	0.1484	0.0532	0.0381	0.0205	0.0244	0.0159	0.0163	0.0083	0.0125	0.0159	0.0254	0.0177	0.0368
400	0.0181	0.0143	0.0261	0.0420	0.0697	0.0357	0.0247	0.0131	0.0189	0.0114	0.0122	0.0068	0.0104	0.0086	0.0141	0.0139	0.0213
450	0.0166	0.0079	0.0150	0.0367	0.0627	0.0245	0.0179	0.0118	0.0175	0.0074	0.0081	0.0064	0.0098	0.0054	0.0079	0.0132	0.0168
500	0.0147	0.0031	0.0056	0.0295	0.0500	0.0225	0.0161	0.0096	0.0149	0.0046	0.0049	0.0059	0.0089	0.0046	0.0068	0.0122	0.0134
550	0.0134	0.0027	0.0048	0.0234	0.0422	0.0190	0.0138	0.0086	0.0137	0.0038	0.0042	0.0056	0.0085	0.0043	0.0063	0.0115	0.0116
600	0.0098	0.0022	0.0038	0.0201	0.0346	0.0166	0.0121	0.0059	0.0096	0.0029	0.0032	0.0041	0.0063	0.0039	0.0058	0.0083	0.0093
650	0.0067	0.0020	0.0033	0.0183	0.0305	0.0140	0.0103	0.0045	0.0062	0.0022	0.0024	0.0022	0.0034	0.0034	0.0049	0.0047	0.0074
700	0.0045	0.0020	0.0033	0.0092	0.0170	0.0132	0.0096	0.0030	0.0046	0.0022	0.0024	0.0016	0.0026	0.0029	0.0044	0.0036	0.0054
750	0.0035	0.0022	0.0037	0.0054	0.0108	0.0104	0.0076	0.0025	0.0039	0.0021	0.0023	0.0015	0.0023	0.0023	0.0036	0.0032	0.0042
800	0.0033	0.0018	0.0032	0.0050	0.0094	0.0082	0.0062	0.0020	0.0034	0.0017	0.0019	0.0014	0.0022	0.0020	0.0030	0.0030	0.0036
850	0.0025	0.0023	0.0043	0.0042	0.0074	0.0062	0.0049	0.0013	0.0024	0.0015	0.0016	0.0010	0.0016	0.0019	0.0028	0.0022	0.0030
900	0.0021	0.0033	0.0062	0.0041	0.0070	0.0058	0.0046	0.0011	0.0019	0.0017	0.0019	0.0007	0.0012	0.0018	0.0027	0.0018	0.0030
950	0.0020	0.0044	0.0081	0.0039	0.0067	0.0057	0.0045	0.0011	0.0018	0.0018	0.0021	0.0007	0.0011	0.0018	0.0026	0.0017	0.0031
1000	0.0019	0.0053	0.0098	0.0035	0.0060	0.0057	0.0044	0.0009	0.0017	0.0018	0.0023	0.0006	0.0011	0.0016	0.0024	0.0016	0.0032

******************************** PLUME CHLORIDE DEPOSITION TABLE (G./(M.**2-10 DAYS)) ********************************

INDIANTOWN, 1982-86 WEST PALM BEACH MET. DATA (LMDCT, 10 CYCLES)

SEASON=WINTER

DISTANCE FROM TOWER (M)	WIND FROM N / PLUME HEADED S	NNE / SSW	NE / SW	ENE / WSW	E / W	ESE / WNW	SE / NW	SSE / NNW	S / N	SSW / NNE	SW / NE	WSW / ENE	W / E	WNW / ESE	NW / SE	NNW / SSE	AVG / AVG
100	2.635	0.773	1.426	2.412	6.219	2.420	3.574	2.475	3.038	1.184	1.228	1.149	2.066	2.281	3.538	2.795	2.451
150	0.373	0.129	0.227	0.353	0.907	0.254	0.389	0.349	0.453	0.247	0.241	0.180	0.331	0.287	0.440	0.432	0.349
200	0.111	0.053	0.091	0.125	0.323	0.092	0.152	0.108	0.128	0.103	0.105	0.048	0.094	0.080	0.117	0.112	0.115
250	0.075	0.043	0.083	0.065	0.167	0.057	0.091	0.063	0.083	0.065	0.071	0.034	0.067	0.051	0.074	0.087	0.074
300	0.056	0.015	0.026	0.048	0.122	0.034	0.052	0.047	0.063	0.032	0.031	0.027	0.051	0.042	0.065	0.068	0.049
350	0.033	0.011	0.016	0.034	0.089	0.031	0.046	0.034	0.041	0.023	0.021	0.015	0.027	0.039	0.061	0.034	0.035
400	0.023	0.007	0.009	0.017	0.044	0.022	0.034	0.020	0.028	0.018	0.016	0.011	0.020	0.022	0.033	0.028	0.022
450	0.021	0.004	0.005	0.015	0.039	0.013	0.022	0.018	0.026	0.012	0.012	0.011	0.019	0.009	0.014	0.026	0.017
500	0.019	0.002	0.002	0.012	0.031	0.012	0.020	0.015	0.022	0.007	0.007	0.010	0.017	0.008	0.012	0.024	0.014
550	0.017	0.002	0.002	0.009	0.025	0.010	0.017	0.013	0.020	0.006	0.006	0.009	0.016	0.008	0.012	0.023	0.012
600	0.013	0.001	0.001	0.008	0.020	0.009	0.015	0.010	0.015	0.005	0.004	0.007	0.012	0.008	0.011	0.017	0.010
650	0.008	0.001	0.001	0.007	0.018	0.008	0.013	0.007	0.009	0.003	0.003	0.004	0.007	0.007	0.010	0.009	0.007
700	0.006	0.001	0.001	0.003	0.009	0.007	0.012	0.005	0.007	0.003	0.003	0.003	0.005	0.006	0.009	0.007	0.005
750	0.005	0.001	0.001	0.002	0.006	0.006	0.010	0.003	0.006	0.003	0.003	0.002	0.004	0.005	0.007	0.006	0.004
800	0.005	0.001	0.001	0.002	0.005	0.004	0.007	0.003	0.005	0.003	0.003	0.002	0.004	0.004	0.006	0.006	0.004
850	0.004	0.001	0.001	0.002	0.004	0.003	0.006	0.002	0.004	0.002	0.002	0.002	0.003	0.004	0.006	0.005	0.003
900	0.003	0.001	0.001	0.001	0.004	0.003	0.005	0.002	0.003	0.003	0.002	0.001	0.002	0.004	0.006	0.003	0.003
950	0.003	0.001	0.002	0.001	0.003	0.003	0.005	0.002	0.003	0.003	0.002	0.001	0.002	0.004	0.006	0.003	0.003
1000	0.003	0.001	0.002	0.001	0.003	0.003	0.005	0.002	0.003	0.003	0.003	0.001	0.002	0.004	0.006	0.003	0.003

QUESTION 39

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

PM and PM_{10} should be viewed as separate pollutants and emissions and controls discussed separately.

RESPONSE

As discussed in Section 10.6 of the BACT analysis for the project, the conservative assumption has been made that all the particulate matter (PM) emitted from the project will be less than 10 microns in diameter. Thus for the purpose of the modeling and BACT analyses, all the TSP emitted is assumed to be PM_{10}. It is possible that this assumption is overconservative in that some fraction of the PM emitted will have a diameter greater than 10 microns; however, ICL feels that there is no reliable information that can be used to accurately assess what this fraction will be. This approach was discussed with Preston Lewis, FDER.

The PSD modeling analysis presented demonstrates that the facility will comply with the NAAQS and increments for PM_{10} even assuming all TSP has a diameter less than 10 microns.

Similarly, the BACT analysis for the PC boiler demonstrates that there is no technologically feasible control alternative which offers a greater degree of control of PM_{10} than the use of a fabric filter. As described in section 10.6.2 the fabric filter offers greater control of fine particulate than the alternative electrostatic precipitator (ESP), which is more effective at capturing larger particles than smaller particles. Therefore, a fabric filter would be concluded to represent BACT for this application for both TSP and PM_{10}, and since all the TSP is considered to be PM_{10}, the pollutants were considered together in this analysis.

For the natural gas- and oil-fired auxiliary boiler, control alternatives include electrostatic precipitators and firing a fuel with a low ash content. Fabric filters are not technologically feasible for oil-fired sources due to blinding of the bags by the sticky particulate produced when firing oil. The ESP, however, is prohibitively expensive in this case since the auxiliary boiler will produce extremely low levels of PM and only operate for 1000 hours per year.

The BACT analysis demonstrates that the annual cost of operating an ESP on this source would be $480,000 per year, and that the maximum reduction in TSP emissions would be 3.5 tons per year for a cost effectiveness of over $137,000 per ton TSP. Particle size data from oil-fired sources presented in Table 10.6-5 shows that approximately 95 percent of the PM emitted from these sources is less than 10 microns in diameter. Therefore, the maximum reduction in PM_{10} emissions would be 3.3 tons per year, for a cost effectiveness of over $144,000 per ton PM_{10}. In either case, an ESP is clearly not cost effective, and therefore unrepresentative of BACT.

As the next most stringent alternative, and in the absence of adverse energy, adverse environmental and economic impacts, the use of low ash fuels (natural gas and No. 2 fuel oil) is thus representative of BACT for both TSP and PM_{10} from the auxiliary boiler.

REFERENCES:

USEPA (1986). National Dioxin Strategy Tier 4 - Combustion Sources. Engineering Analysis Report. EPA 450/4-24-014h.

Kimble, B. J. and M. L. Gross (1980). "Tetrachlorodibenzo-p-dioxin Quantitation in Stack-Collected Coal Fly. Science. 207:59-61.

Junk, G. A. and J. J. Richard (1981). "Dioxins Not in Effluents From Coal/Refuse Combustion." Chemosphere 10:1237-1241.

Haile, C. L. et al (1984). Emissions of Organic Pollutants from Coal-Fired Utility Boiler Plants; Identification and Analysis of Organic Pollutants in Air. (L. H. Keith, Ed.) New York; Butterworth Publishers.

Harless, R. L. and R. G. Lewis (1982). "Quantitative Determination of 2,3,7,8-TCDD Residues by GC/MS. USEPA Health Effects Research Laboratory, Research Traingle Park, N.C.

DeRoos, F. L. and A. Bjorseth (1979). TCDD Analysis of Fly Ash Sample. U.S. EPA Research Triangle Park, NC. EPA Contract No. 68-02-2686.

QUESTION 40

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

On page 3.4.3-4 please estimate the minimum recirculation (below 25% expected) of flue gas recirculated and the impact on the emission control systems. Recalculate the emissions, if required and provide the necessary tables.

RESPONSE

Alternative control technologies for nitrogen oxides are discussed in Section 3.4.3.1 of the SCA. As stated on page 3.4.3-3, for fossil fuel auxiliary boilers with restricted operating hours, the use of flue gas recirculation or low NO_X burners is more common than the use of SCR or SNCR due to the high cost of add-on controls. Both of the lower cost control technologies were discussed in the text for the auxiliary boiler NO_X emissions. Based on the consideration of economic, energy, and environmental impacts it is concluded that the use of low NO_X burners represents BACT for control of NO_X emissions from the auxiliary boiler as presented on page 3.4.3-9 of the SCA. Since the flue gas recirculation method is not employed in the nitrogen oxides reduction control, no recalculation of the emissions is necessary.

QUESTION 41

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

Table 3.4.3-1 provides a capital cost advantage for SNCR compared to SCR of about 5:1 with the same amount of control. What is the basis of the cost estimates (firm manufacture quotes, etc.). Considering reasonable maintenance practices what, if any, will be the degradation of air emissions control over the life of the project. Use probabilities to demonstrate uncertainty.

RESPONSE

As described in the BACT analysis presented as Appendix 10.1.5 to the SCA, cost estimates for both the SCR and SNCR NO_x control alternatives were prepared using the same methodology, so as to provide a common basis of comparison. Equipment capital cost estimates for both alternatives were obtained directly from vendor cost quotations, and total capital costs and annual operating costs were estimated based on methodology presented in the latest EPA guidance on the subject ("OAQPS Control Cost Manual," EPA 450/3-90-006; January 1990).

Since neither SCR nor SNCR has ever been applied on a commercial scale to a PC boiler firing domestic coals, the equipment design in either case must contain sufficient contingency to account for indeterminant process variables in order to assure that the emissions limit will be met. For the proposed BACT (SNCR), inclusion of this contingency in the design will result in the NO_x emission limit of 0.17 lb/MMBtu being met throughout the life of the project.

QUESTION 42

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

Discuss fuel availability/long term contracts, prices and emissions at 8760 hours/yr and expected 1000 hours/year using natural gas and #2 fuel oil as a primary fuel on the auxiliary boiler and as a secondary fuel for the PC boiler.

RESPONSE

Natural Gas

Our steam customer, Caulkin Citrus, requires steam 24 hours per day during their processing season and the ICP is required to provide a backup source of steam should our main boiler be shut down. In the event the main boiler has to be shut down due to an extensive drought or other maintenance reasons during the processing season, the auxiliary boiler must be operated.

This requirement extends the amount of time that the auxiliary boiler may be operated from 1,000 to 5,000 hours. The 5,000 hours would cover the normal processing season for Caulkin Citrus.

A revised BACT analysis, included as Exhibit FDER42-1, discusses the revision in potential operating hours. Revised emission rates for the auxiliary boiler are included as Exhibit FDER42-2.

Therefore, the ICL is requesting approval to operate the auxiliary boiler for up to 5,000 hours, with up to 1,000 hours on oil and the balance on natural gas.

A Letter of Intent was executed on November 9, 1990, regarding supply of natural gas with Indiantown Gas Company. A detailed contract is scheduled for completion by early 1992. Under the agreement, Indiantown Cogeneration will assume the existing natural gas allocation currently being provided to the Caulkin Citrus plant. Currently, pricing of natural gas is in the $3.00/MMBtu range and is expected to escalate generally in accordance with Florida Power & Light's fuel price forecast.

No. 2 Fuel Oil

No. 2 fuel oil will be available to the project from terminal facilities located in Florida. Substantial storage facilities are located at both Port Everglades and Port Canaveral. Likely transportation will be by truck. Contracts are planned to be put in place by early 1992. Current pricing is in the $4.30/MMBtu range and is expected to escalate generally in accordance with the Florida Power & Light fuel forecast.

BACT ADDENDUM FOR AUXILIARY BOILER

INTRODUCTION

PG&E|Bechtel Generating Company is proposing to install and operate a coal-fired cogeneration facility near Indiantown FL. The Prevention of Significant Deterioration (PSD) Application for this project was submitted to the Florida DER for review in December 1990. The application included a Best Avaliable Control Technology (BACT) analysis of the various air pollution control alternatives for the emission units planned for the Indiantown facility.

In the previously sumbitted BACT analysis, the maximum annual operating hours of the natural gas- and #2 fuel oil-fired auxiliary boiler was specified as 1,000 hours/yr. PG&E|Bechtel now feels, however, that this annual operating hours limitation is not sufficient to allow for a "zero water discharge" facility while maintaining steam supply to Caulkins Citrus Processors, especially during periods of severe drought,

This addendum to the BACT analysis presents documentation to support BACT conclusions consistent with a revision to the maximum annual hours of auxiliary boiler operation to 5,000 hours/yr total, with a maximum of 1,000 hours/yr of #2 fuel oil firing.

BACT FOR NO_x

In Section 3.3 of the previously submitted BACT analysis, the alternative NO_x control methods for the auxiliary boiler were identified as selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), flue gas recirculation (FGR), low NO_x burners, and low excess air firing (listed in order of decreasing NO_x control effectiveness). All these control alternatives were concluded to be technically feasible for the proposed gas- and oil-fired boiler; Low NO_x Burners were concluded to be representative of BACT since the more stringent alternatives (SCR, SNCR and FGR) were concluded to be cost ineffective.

Changing the annual operating hours will in no way affect the technical feasibility of any of these alternatives. Similarly, the hourly emission rates associated with each technology will not change if the annual operating hours is increased.

For each alternative, however, both the annual operating cost and annual tons of NO_x controlled will be changed if the auxiliary boiler were to operate for 5,000 hours/yr. Thus the choice of which alternative represents BACT with an annual operating hour restriction of 5,000 hours is based on economic impacts, as was the case in the previously submitted BACT. Therefore, the estimated costs associated with each of these alternatives was revisited for this addendum. These costs are summarized on Tables 1 and 2.

The cost estimating methodology used in this addendum is identical to that outlined in Section 2.2 of the previously-submitted BACT analysis. This methodology is outlined in the most recent EPA Guidance Document on the subject, the OAQPS Control Cost Manual (EPA 1990).

SCR, SNCR and FGR capital costs are independent of annual operating hours. Therefore, the costs of the equipment for these alternatives, determined from vendor information and shown on Table 1, are the same as for the previously subitted BACT (Table 3-6).

Total capital costs for the SCR alternative on the auxiliary boiler are \$1,500,000. Based on 5,000 hours/yr of annual operation, the annual cost of this alternative (Table 2) is estimated at \$776,000/yr. Compared to the NSPS for this size unit, and SCR system designed for 80% control would reduce annual NO_x emissions by 138 ton/yr for a cost effectiveness of \$5,623/ton, which is considered unreasonable and unrepresentative of BACT.

Total capital costs for the SNCR alternative are estimated at \$1,222,000; annual costs are estimated at \$637,500/yr. Based on a control efficiency of 60%, this alternative would control 103 ton/yr and have a cost effectiveness of \$6,189/ton. This is also considered unrepresentative of BACT costs for similar sources.

Capital costs for the FGR alternative are estimated at \$707,000. Annual costs are estimated at \$344,600/yr, with 86 ton/yr controlled assuming a reduction efficiency of 50%. Cost effectiveness of FGR is thus \$4,007/ton; similarly this is considered excessive and unrepresentative of BACT.

There are no adverse impacts, however, associated with the use of Low NO_x Burners. As the next-most stringent alternative, they are thus concluded to represent BACT for the auxiliary boiler operating at a maximum of 5,000 hours/yr.

BACT FOR SO_2

In the previously submitted BACT analysis for the auxiliary boiler, the alternatives for SO_2 control were identified as flue gas desulfurization (FGD) and limiting the fuel sulfur content (Section 4.3). The technical feasibility of these alternatives would not change if the total annual operating hours of the boiler were 5,000 hours/yr.

Tables 4-4 and 4-5 in the previous BACT analysis summarized the capital and annual operating costs of the wet scrubbing FGD process for the auxiliary boiler operating at a maximum of 1,000 hours/yr. These costs would not change as a result of this intended increase in operating hours, since the maximum annual hours the auxiliary boiler will fire #2 fuel oil will not change from 1,000 hours/yr and the natural gas that would be used in the boiler contains no sulfur.

Thus Tables 3 and 4, which summarize the costs of wet scrubbing SO_2 control for the auxiliary boiler, represent no change from the previously submitted cost estimate. As a result, the estimated costs of wet scrubbing FGD (\$810,000 capital cost; \$536,600/yr operating cost; \$65,523/ton controlled) remain the same. These costs are not considered cost effective, and thus unrepresentative of BACT.

In addition, the use of wet scrubbing would result in the generation of approximately 34,000 lb/yr of dissolved sodium compounds, which would present a significant adverse environmental impact for the proposed facility. Adverse energy impacts would be encountered as well; aproximately 8,500 kwhr/yr (1,000 kwhr/ton controlled) would be required for the increased fan power and circulation pump power required by the wet scrubbing alternative.

There are no adverse economic, environmental, or energy impacts associated with firing low sulfur #2 fuel oil, however. This alternative is thus concluded to represent BACT for the auxiliary boiler operating a maxmimum of 1,000 hour/yr on fuel oil.

BACT FOR CO AND VOC

As described in the original BACT submittal, emission control alternatives for CO and VOC from fossil fuel-fired sources are catalytic oxidation and combustion controls. Catalytic controls were determined to be technically infeasible for oil-fired sources, such as the proposed auxiliary boiler, due to the presence of sulfur, ash and trace elements in the flue gas of these sources. Therefore, this alternative is unrepresentative of BACT.

Combustion controls, on the other hand, are the next most stringent control alternative and would result in no adverse economic, environmental or energy impacts in the proposed application. As such, they are considered to be representative of BACT for control of CO and VOC.

BACT FOR PM

In the previously submitted BACT analysis, the technically feasible control alternatives for PM emissions from oil-fired sources were concluded to be electrostatic precipitators (ESPs) and firing low sulfur fuel oil. The use of an ESP, however, was concluded to be economically infeasible at over $130,000/ton controlled. The capital and annual operating costs presented in the previous report are included in this analysis as Tables 5 and 6. Since the emissions of PM during periods of gas firing will be virtually negligible and the annual hours of operation on oil firing will remain at 1,000/yr (the same as in the previous submittal), the annual tons of PM emitted from the auxiliary boiler is not expected to increase. The estimated annual operating costs of, and annual tons of PM controlled by, an ESP would thus not change. Therefore, the use of an ESP is still concluded to be economically infeasible and unrepresentative of BACT.

The use of low sulfur fuel oil and natural gas for controlling PM from the auxiliary boiler is thus concluded to represent BACT for control of PM from the auxiliary boiler.

Exhibit FDER42-1

TABLE 1

Capital Costs of Auxiliary Boiler NO_x Control Alternatives

	SCR	SNCR	FGR
DIRECT CAPITAL COSTS			
(1) Purchased Equipment			
(a) Basic Equipment	675,000	470,000	318,000
(b) Auxiliaries	included	included	included
(c) Instrumentation and Controls	68,000	47,000	32,000
(d) Structural Support	68,000	47,000	32,000
(e) Freight & Taxes	65,000	45,000	31,000
(2) Direct Installation	263,000	183,000	124,000
TOTAL DIRECT COSTS (TDC)	$1,139,000	$792,000	$537,000
(3) Indirect Installation			
(a) Engineering & Supervision	114,000	79,000	54,000
(b) Construction & Field	114,000	79,000	54,000
Expense	57,000	40,000	27,000
(c) Construction Fee	34,000	24,000	16,000
(d) Contingencies			
(4) Other Indirect Costs			
(a) Startup & Performance Test	11,000	8,000	5,000
(b) Working Capital	33,000	27,000	15,000
(c) License Fee	-	175,000	-
TOTAL INDIRECT COSTS (TIC)	$363,000	$432,000	$171,000
TOTAL CAPITAL COST (TCC)	$1,502,000	$1,224,000	$708,000
(5) Annualized Capital Recovery	$244,000	$199,000	$115,000
Cost Factors: 1990 OAQPS Control Cost Manual			

TABLE 2

Annual Costs for Auxiliary Boiler NO_x Control Alternatives

	SCR	SNCR	FGR
DIRECT OPERATING COSTS			
(1) Labor (a) Operating (b) Supervisory	 $87,600 13,000	 $87,600 13,000	 - -
(2) Maintenance (a) Labor (b) Supplies (50% Maint. Labor)	 107,100 54,000	 107,100 54,000	 87,600 44,000
(3) Replacement Parts (a) Catalyst (1) (b) Equipment	 41,000 68,000	 - 47,000	 - 32,000
(4) Utilities (a) Air (b) Steam (c) Electricity	 - - 35,500	 - 20,000 3,000	 - - 22,000
(5) Raw Materials - Ammonia	14,500	8,800	-
(6) Catalyst Disposal	1,300	-	-
INDIRECT OPERATING COSTS			
(7) Overhead	50,000	50,000	16,000
(8) Taxes	15,000	12,000	7,000
(9) Insurance	15,000	12,000	7,000
(10) Administration	30,000	24,000	14,000
ANNUAL OPERATING COSTS	$532,000	$438,500	$229,600
ANNUAL CAPITAL AND OPERATING COSTS	$776,000	$637,500	$344,600
Annual Tons Removed (2)	138	103	86
Cost Effectiveness ($/ton)	$5,623	$6,189	$4,007

Notes:
(1) catalyst replacement at 50% in five years
(2) compared to NSPS 0.2 lb/MMBtu with 5,000 annual operating hours

TABLE 3

Capital Costs for Auxiliary Boiler SO_2 Control

DIRECT CAPITAL COSTS	
(1) Purchased Equpment (a) Basic Equipment (b) Auxiliaries (c) Instrumentation (d) Structural Support (e) Freight & Taxes	\$360,000 included 36,000 36,000 35,000
(2) Direct Installation	140,000
TOTAL DIRECT COSTS (TDC)	\$607,000
INDIRECT COSTS	
(3) Indirect Installation (a) Engineering & Supervision (b) Construction & Field Expenses (c) Construction Fee (d) Contingencies	 61,000 61,000 30,000 18,000
(4) Other Indirect Costs (a) Startup & Performance Testing (b) Working Capital	 6,000 27,000
TOTAL INDIRECT COSTS (TIC)	\$203,000
TOTAL CAPITAL COST (TCC)	\$810,000
(5) Annualized Capital Recovery	\$131,000/yr

TABLE 4

Annual Costs for Auxiliary Boiler SO_2 Control

DIRECT OPERATING COSTS	
(1) Labor (a) Operating (b) Supervisory	 $87,600 13,000
(2) Maintenance (a) Labor (b) Supplies	 107,100 54,000
(3) Replacement Parts	36,000
(4) Utilities (a) Air (b) Steam (c) Electricity	 - 2,900 20,000
(5) Raw Materials - Sodium Hydroxide	2,300
(6) Waste Disposal	500
INDIRECT OPERATING COSTS	
(7) Overhead	50,000
(8) Taxes	8,000
(9) Insurance	8,000
(10) Administration	16,000
TOTAL ANNUAL OPERATING COSTS	$405,600
ANNUAL CAPITAL AND OPERATING COSTS	$536,600
Annual Tons SO_2 Removed (1)	8.4
Cost Effectiveness ($/ton)	$63,523

Note:
(1) compared to 0.052 lb/MMBtu with 1,000 maximum annual operating hours on #2 fuel oil

TABLE 5

Capital Cost Components for an Electrostatic Precipitator

DIRECT CAPITAL COSTS	
(1) Purchased Equipment (a) Basic Equipment (b) Auxiliaries (c) Instrumentation (d) Structural Support (e) Freight & Taxes	 $292,000 102,000 29,000 29,000 36,000
TOTAL PURCHASED EQUIPMENT COSTS	$488,000
(2) Direct Installation	146,000
TOTAL DIRECT COSTS (TDC)	$634,000
(3) Indirect Installation (a) Engineering & Supervision (b) Construction & Field Expenses (c) Construction Fee	 63,000 63,000 95,000
TOTAL INDIRECT INSTALLATION COST	$221,000
(4) Other Indirect Costs (a) Startup & Performance Testing (b) Working Capital (c) Interest During Construction	 6,000 8,000 49,000
TOTAL INDIRECT COSTS (TIC)	$63,000
TOTAL CAPITAL COST (TCC)	$918,000
(5) Annualized Capital Recovery	$159,000/yr

TABLE 6

Annual Costs for an Electrostatic Precipitator

DIRECT OPERATING COSTS	
(1) Labor (a) Operating (b) Supervisory	 $55,000 8,000
(2) Maintenance	32,000
(3) Replacement Parts	36,000
(4) Utilities (a) Air (b) Steam (c) Electricity	 - - 131,000
(5) Raw Materials	-
INDIRECT OPERATING COSTS	
(7) Overhead	23,000
(8) Taxes	9,000
(9) Insurance	9,000
(10) Administration	18,000
(11) Capital Recovery	$159,000
ANNUAL CAPITAL AND OPERATING COSTS	$480,000
Annual Tons PM Removed	3.5
Cost Effectiveness ($/ton)	$137,000

QUESTION 42
EMISSION ESTIMATES FOR THE AUXILIARY BOILER

POLLUTANTS	EMISSION ESTIMATES			
	lb/hr	ton/yr		
		8760 hrs	5000 hrs	1000 hrs
#2 FUEL OIL FIRING				
Nitrogen Oxides	68.4	299.5	(1)	34.2
Sulfur Dioxide	17.8	78.0	(1)	8.9
Carbon Monoxide	47.3	207.1	(1)	23.7
VOC	0.63	2.7	(1)	0.3
PM	1.4	6.1	(1)	0.7
Lead	3.6×10^{-2}	0.2	(1)	1.8×10^{-2}
NATURAL GAS FIRING				
Nitrogen Oxides	68.4	299.5	171.0	(2)
Sulfur Dioxide	nil	nil	nil	(2)
Carbon Monoxide	47.3	207.1	118.3	(2)
VOC	0.63	2.7	1.6	(2)
PM	nil	nil	nil	(2)

Notes:
(1) Auxiliary boiler will operate a maximum of 1,000 hours/yr on #2 fuel oil
(2) Auxiliary boiler will operate for a maximum of 5,000 hours/yr total

QUESTION 43

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

What level of NO_X emissions are expected using low NO_X burners with natural gas as a fuel in the auxiliary boiler?

RESPONSE

Using low NO_X burners with natural gas as a fuel in the auxiliary boiler, the estimated level of NO_X emissions is 0.1 lb/MMBtu (35.8 lb/hr).

QUESTION 44

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

The analyses for using the alternative control technologies for the PC boiler (i.e. scrubbers and SNCR) should consider controlling emissions from the auxiliary boiler as well. Please provide feasibility and cost information.

RESPONSE

The auxiliary boiler will be operated (to a maximum of 5,000 hours as described in the response to FDER Question 42) only during periods when the PC boiler is not operating or is being heated up or cooled down, such as during maintenance outages, startup, and shutdown. The two units will be physically separate from each other and will have separate exhaust stacks.

If used on either the auxiliary boiler or PC boiler, SNCR would require injection of the reducing agent directly into each boiler's combustion chamber. It is not technically feasible for a common SNCR system to be used by both boilers. A revised BACT analysis for operating the auxiliary boiler for 5,000 hours is included in the response to FDER Question 42.

Additionally, the auxiliary boiler will have approximately one-tenth the flue gas flow rate of the PC boiler. The dry scrubbing SO_2 control system will be designed and sized to treat flue gas at the rate generated by the PC boiler. Because this type of SO_2 control device achieves emissions reduction through flue gas cooling and evaporation, the amount of flue gas to be treated is critical for sizing the spray dryer vessel. Due to the magnitude of difference between the flue gas rates of the two boilers, it is not technically feasible for both units to use a common scrubbing device.

QUESTION 45

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

Please discuss the capability of using either conventional or Gore-Tex bags in the baghouse. Provide basis for all cost estimates (firm manufacture quotes, etc.) - Reference Page 3.4.3-17.

RESPONSE

The ICP will employ a fabric filter for control of particulate matter from the PC boiler. The baghouse would be capable of utilizing either conventional woven bags or Gore-Tex bags. However, based on current vendor cost information, Gore-Tex bags cost approximately $270 more per bag than the conventional bags, for a cost effectiveness of over $9,000 per ton of additional PM removed by going to Gore-Tex bags.

QUESTION 46

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

Over the life of the facility please discuss the availability of "low sulfur coal" for this project (long term contracts, etc.). Provide contingency plans for continuing facility operation after the plant stockpile of "low sulfur coal" is used (supply interruption).

RESPONSE

The southern Appalachian coal supply region, which is the economic supply region due to transportation logistics, has vast reserves of high quality coal.

The project intends to finalize its coal supply/ash disposal agreement by early 1992. Enclosed are letters from several bidders (Exhibit FDER46-1) indicating their reserves of the specified coal, which greatly exceed the need for the life of the project.

The intent of the emergency coal storage pile is to maintain operation during most scenarios of supply interruption. Our analysis indicates a very low risk of exhausting this pile. In the unlikely event that the inactive pile were exhausted and ongoing delivery of coal remained curtailed, then the facility's main boiler would be shut down. In such an event the facility would continue to operate using its auxiliary boiler firing natural gas/oil.

Exhibit FDER46-1

LETTERS FROM BIDDERS

Exhibit FDER46-1

Coastal
The Energy People

March 19, 1991

Mr. Stephen A. Sorrentino
Project Development Manager
PG&E Bechtel Generating Company
7475 Wisconsin Avenue, Suite 1000
Bethesda, Maryland 20814-3422

Dear Steve:

As requested, attached is a chart showing a breakdown on Coastal Coal's resource base. We would be interested in pursuing a 20-year contract with your company and feel we easily have the capacity to ship up to 500,000 tons per year from our various eastern coal operations.

The specifications (as received basis) you discussed with me were as follows:

Sulfur %:	2.0 Maximum
Ash %:	12.0 Maximum, 9.0 Preferred
Btu:	11,800 Minimum

At this time, we would have no problems meeting these specifications for a 20-year commitment from any of our operations.

Regarding ash backhaul from your Florida project, I am attaching the summary I presented to you in my January 30, 1991 letter. At this time, this response is all Coastal Coal can make on ash removal.

Steve, please let me know if additional information is needed and I look forward to continuing discussions with you on this project.

Best regards,

Gene McBurney/sam

Gene McBurney, Jr.
District Manager
Southeast Region

sam/977

Enclosures

Coastal Coal Sales, Inc.
A SUBSIDIARY OF THE COASTAL CORPORATION
P O BOX 1871 • ROANOKE VA 24008 • 703-983-0222 • TLX 898415 • FAX 703-983-0267

Coastal Coal Sales, Inc.
A SUBSIDIARY OF THE COASTAL CORPORATION

Table 1

COASTAL COAL GROUP

Compilation of Landholdings and Resource Base

Clean Recoverable Reserves and Resources
(Proven and Probable Tons X 1000)

State	Leased To Others	Available for Development: Reserves	Available for Development: Cond. Reserves	Available for Development: Resources	Total Reserves and Resources
VA	6,741.3	64,615.3	44,367.3	63,040.4	178,764.3
KY	162,012.6	32,369.2	3,025.6	29,372.0	226,779.4
WV	31,500.0	98,862.6	86,500.0	-	216,862.6
UT	-	122,614.5	-	-	122,614.5
TX	-	168,000.0	-	-	168,000.0
	200,253.9	486,461.6	133,892.9	92,412.4	913,020.8

Landholdings
(Acres)

State	Owned: Fee	Owned: Mineral	Owned: Surface	Controlled By Lease and Exchange	Total
VA	22,116	38,983	1,459	21,233	83,791
KY	9,251	64,328	1,225	5,563	80,367
WV	2,167	36,157	1,166	22,979	62,469
UT	-	640	-	13,045	13,685
TX	-	-	-	17,000	17,000
	33,534	140,108	3,850	79,820	257,312

Note: Reserves are those tonnages, expressed on a recoverable basis, which are deemed currently minable and merchantable.

Conditional Reserves & Resources are those tonnages, expressed on a recoverable basis, for which the minability or merchantability are less certain under current market conditions.

7/89

WASTE REMOVAL INFORMATION

Kentucky

Coastal Coal Sales, Inc. (CCS) is willing to provide a disposal site located near our Kentucky mines for the coal ash from the proposed facility. This is contingent on obtaining all necessary permits and appropriate financing.

CCS will construct and operate this disposal site and charge PG&E Bechtel Generating Company estimated costs, that are subject to refinement, of approximately $ per ton in current dollars. This amount does not include rail rates from plant to unloading site.

It is the best interest of the project to find a local market for the waste product and CCS will support this endeavor to the fullest.

West Virginia

Seller has received a modification to its Kingwood mine refuse disposal permit to accept coal ash from a fluidized-bed combustion plant. This permit would need to be modified to accept the pulverized coal ash and FGD waste and is conditionally approved subject to satisfying certain conditions. The cost of waste disposal would be $ per ton. This amount does not include rail rates from plant to unloading te.

Coastal Coal Sales, Inc. proposes to provide complete ash management services for the project, including construction of a pelletization facility for an additional estimated $ million and $ ton to pelletize the ash for transport.

sam/876

Exhibit FDER46-1
APR 2 1991

COSTAIN

COSTAIN COAL INC. S. Sorrentino

249 EAST MAIN STREET - SUITE 200 ■ LEXINGTON, KY. 40507 ■ 606/255-4006
FAX: 606/231-6520

March 28, 1991

PETER R. P. SCHMIDT
DIRECTOR OF EASTERN DIVISION
SALES / COGENERATION

Mr. Stephen A. Sorrentino
Project Development Manager
PG&E-Bechtel Generating Company
7475 Wisconsin Avenue - Suite 1000
Bethesda, MD 20814-3422

Dear Mr. Sorrentino:

Per our phone conversation of March 12th in which you requested information regarding Costain Coal's reserve base and the status of ash disposal at our various mines, I trust the information found below will address most of your concerns.

Costain Reserve Base:

As can be determined from the enclosed brochure, Costain has a substantial reserve base in Kentucky and West Virginia to meet the coal and term offered in our letter of July 26, 1990.

Eastern Kentucky	55 Million
Western Kentucky	310 Million
West Virginia	60 Million

Costain is constantly adding reserves to its base, replacing the annual company production of approximately 18 million tons. As you are aware, Costain is the long-term supplier on two other cogeneration projects and our reserve base has been evaluated by the financial lenders in those projects. The lenders felt Costain, being one of the top producing coal companies in the United States, has ample reserves to supply their two projects and several more of similar term and tonnage.

Ash Disposal:

As you are aware, Costain Coal Inc. will be the fuel supplier on the AES Cedar Bay Florida project. In addition to supplying fuel under a 20-year contract, we will be responsible for the disposal of 150,000 tons of pelletized fluidized bed ash annually for 20 years. By early 1992 Costain should have a fully-permitted waste disposal site at our Prater Creek mining operation in Eastern Kentucky. Our Jim Smith operation, located in Western Kentucky is currently disposing of ash waste from a local utility.

Exhibit FDER46-1

Enclosed is a brochure describing Creative Resource Management, a Costain Holdings subsidiary involved with permitting, design, and management of waste disposal facilities. Costain is presently reviewing the possibility of ash disposal sites at all our operations, providing our fuel customers with a variety of disposal options.

Steve, Costain remains very interested in your project. After negotiating a very competitive fuel supply and transportation package for the AES project, I feel confident Costain can provide a similar package for your Florida project. I look forward to meeting with you during the next month to discuss this further. Please call with any additional questions or concerns.

Regards,

COSTAIN COAL INC.

Peter

Peter R. P. Schmidt
Director of Eastern Division
Sales/Cogeneration

PRPS/bss
Enclosure

cc: J. Willson

Exhibit FDER46-1

Kentucky Criterion Coal Company (KCCC)

KCCC will produce and sell coal to the Indiantown Cogeneration Project. KCCC is a wholly owned subsidiary of Criterion Coal Company (KCCC), which is a wholly owned subsidiary of Westmoreland.

KCCC was formed with the acquisition of a large tract of mineral and surface acreage on July 1, 1987. KCCC controls 8,000 surface acres and 27,000 mineral acres of reserves located around Deane, Letcher County, Kentucky. Presently, all production from the reserves is mined by four independent contractors operating five mines. .

Reserves:

KCCC controls approximately 27,000 mineral acres with in-place reserves of 96 million and clean recoverable reserves of 63 million tons. Aproximately one half of the reserves have sulfur content of less than 1.2 lb SO2/MMBtu. Reserves are contained in the following seams:

Seam	Clean Recoverable Tons (As of 12/31/89)
Hazard #6	68,000
Hazard #5A	1,076,000
Hamlin	742,758
Hazard #4 Rider	1,940,298
Hazard #4	32,056,007
Whitesburg	1,399,215
Elkhorn #3	26,710,200
TOTAL	63,992,478

Estimated Recovery Level = 65%

Exhibit FDER46-1

Ash Disposal Proposal

Disposal Site: Kentucky Criterion Coal Company
Location: Deane Kentucky

Westmoreland Coal Company and JTM Industries, a subsidiary of the Union Pacific Railroad, will dispose of all ash from the project at a site to be permited at Kentucky Criterion Coal Company. At this time, we anticipate that the cost of disposal will be approximately _ per ton. This price is subject to Westmoreland's receiving the necessary permits for disposal at the mine site.

Westmoreland and JTM have already established a business relationship at four 68 MW cogeneration projects which Westmoreland owns in Virginia. JTM is disposing of the ash from all of these projects.

JTM Industries Background

JTM Industries, Inc. (JTM) is one of the largest ash management companies in the United States, with total sales in 1989 of over 1 million tons of fly ash and bottom ash from electric utility generating plants. In addition, JTM handled over 3 million tons of coal combustion by-products for disposal and utilization purposes.

JTM subsidiaries include:

* Ash Sales and Marketing - markets and disposes of fly ash, bottom ash, and scrubber sludge nationwide.

* Mineral By-Products Division - markets lime and cement kiln dust, fluidized bed ash, and other mineral by-products throughout the United States.

* KBK Enterprises, Inc. - provides engineering and consulting services in the areas of ash handling equipment design, ash management, utilization, marketing, environmental assessments and permitting, and real estate development utilizing coal combustion by-products.

JTM is actively involved and has many years of experience in the methods of utilization and disposal of conventional coal combustion processes. The company presently has contracts with utility and industrial coal ash producers for fly ash and bottom ash disposal. JTM is also active in the utilization of coal ash, having several contracts to market fly ash and bottom ash, and is the largest supplier of coal ash for use as raw cement feedstock in the United States.

JTM recognizes that the by-products from non-utility generators will demand special attention for proper disposal and utilization. JTM realizes that methods developed for conventional by-products will need modification or new methods to manage by-products from new clean coal technology plants JTM has been involved in the research and development of methods to utilize and dispose of ash from both fluidized bed and lime scrubber (dry or wet) facilities. With this objective, JTM has invested over 1.5 million dollars in its research and development facilities near Atlanta, GA.

Exhibit FDER46-1

JTM Utility Generator Contracts:

Appalachian Power John Amos Plant	Marketing of Fly Ash and Bottom Ash
Houston Lighting and Power W.A. Parrish Plant	Marketing and Disposal of Fly Ash and Bottom Ash
Houston Lighting and Power Limestone Plant	Disposal of Fly Ash, Bottom Ash and Sludge
Georgia Power Plant Bowen	Marketing of Bottom Ash
Pennsylvania Power and Light Montour Plant	Marketing of Fly Ash
Pennsylvania Power and Light Brunner Island Plant	Marketing of Bottom Ash
Carolina Power and Light Mayo Plant Roxborough Plant	Marketing of Fly Ash
Utah Power and Light All Plants	Marketing of Fly Ash
Public Service Company San Juan Plant	Marketing of Fly Ash
Jacksonville Electric Authority St. John's River Plant	Marketing of Fly Ash And Bottom Ash
Duke Power Company Belews Creek Plant	Marketing of Bottom Ash
Riverbend Plant	Utilization of ponded ash
Tennessee Valley Authority Bull Run Plant	Disposal of Fly Ash
Plant Allen	Utilization of Fly Ash
	Various Engineering and Marketing Studies

Exhibit FDER46-1

Non-Utility Generator Contracts:

Cogentrix Southport Plant	Utilization of Fly Ash and Bottom Ash
Westmoreland Hadson Partners Virginia Plants (4)	Utilization of Fly Ash, Bottom Ash, and Dry Scrubber Waste
Black River Ltd Partnership	Marketing of FBC Ash

Exhibit FDER46-1

MAR 2 7 1991

S. Sorrentino

AMVEST COAL SALES, INC.

ONE BOAR'S HEAD PLACE P.O. BOX 5347 CHARLOTTESVILLE, VIRGINIA 22905-5347 TELEPHONE 804-977-3350 TELEX 822-459 FAX 804-972-7741

DAYTON E. EISEL, III
REGIONAL SALES MANAGER
DIRECT DIAL 804-972-7770

March 25, 1991

Mr. Stephen A. Sorrentino
Project Development Manager
PG&E/Bechtel Generating Company
7475 Wisconsin Avenue
Bethesda, MD 20814

Dear Steve:

This letter is to confirm our interest in supplying coal to the Indiantown Cogeneration Project being developed by your firm. In a preliminary proposal, we indicated our interest in supplying all of the project's coal requirements, anticipated to be approximately 1,250,000 net tons per year, from our Powell Mountain Coal Company operations located in Lee County, Virginia and Harlan County, Kentucky. Sufficient reserves of acceptable quality coal are in place there to supply this quantity of fuel for the 20-year term we have discussed.

Further, we understand that you will require ash disposal services for boiler ash and scrubber by-products, and are proceeding with the preliminary activities necessary to provide this service at our mine. Of course, final details will be established as we finalize of supply/disposal agreement.

Steve, we look forward to continuing to work with you on the Indiantown Cogeneration Project. Please feel free to call me whenever I can be of assistance.

Sincerely,

Dayton Eisel

Dayton E. Eisel, III

DEE:dmk

MAR 2 1 1991

S. Sorrentino

W. G. Karis
Executive Vice President
Administration

Consolidation Coal Company
Consol Plaza
Pittsburgh, Pennsylvania 15241
(412) 831-4122

March 19, 1991

Mr. Stephen A. Sorrentino
Project Development Manager
PG&E-Bechtel Generating Company
7475 Wisconsin Avenue
Bethesda, MD 20814-3422

Dear Mr. Sorrentino:

This letter is to advise you that there are substantial coal reserves from both a quality and logistical standpoint that can serve the proposed Indiantown project. Focusing only on CSX origin coals located in eastern Kentucky (the most likely, but not the only potential region to supply the project), the Department of Energy reports that there are 4.8 billion recoverable tons of coal that contain less than 1.7 lbs. sulfur/MMBtu and more than 11,500 Btu/lb. (EPA report "Estimation of U.S. Coal Reserves by Coal Type, Heat and Sulfur Content," October 1989). This sulfur content equates to 2.0% at 12,000 Btu/lb. At current production rates in eastern Kentucky, this is approximately a 50-year supply for this type of coal.

Please feel free to call me if I can be of further assistance.

Sincerely,

William G. Karis

WGK/meg

Exhibit FDER46-1

MAR 2 1 1991

W. G. Karis
Executive Vice President
Administration

Consolidation Coal Company S. Sorrentino
Consol Plaza
Pittsburgh, Pennsylvania 15241
(412) 831-4122

March 19, 1991

Mr. Stephen A. Sorrentino
Project Development Manager
PG&E-Bechtel Generating Company
7475 Wisconsin Avenue
Bethesda, MD 20814-3422

Dear Mr. Sorrentino:

This letter is to advise you that Consolidation Coal Company plans to bid on both the supply of coal to and disposal of coal ash residue from the proposed Indiantown project.

Disposal of coal ash residue from cogeneration and independent power projects is becoming a rapidly growing business for coal companies such as Consol that intend to be a major supplier to such projects. Ash disposal is a logical extension of our existing mining operations. We already have signed a contract for the disposal of up to 160,000 tons per year of ash residue/dry scrubber waste from a cogeneration plant that will be coming on line in New Jersey by late 1993. We are in the final stages of receiving a permit for the disposal site for this project. We believe that our many years of mining and reclamation experience position us well for the disposal of ash residue in an economic and environmentally sound manner.

Please feel free to call if I can be of further assistance.

Sincerely,

William G. Karis

WGK/meg

Exhibit FDER46-1

AMVEST COAL SALES, INC.
ONE BOAR'S HEAD PLACE P.O. BOX 5347 CHARLOTTESVILLE, VIRGINIA 22905-5347 TELEPHONE 804-977-3350 TELEX 822-459 FAX 804-972-7741

DAYTON E. EISEL, III
REGIONAL SALES MANAGER
DIRECT DIAL 804-972-7770

March 25, 1991

Mr. Stephen A. Sorrentino
Project Development Manager
PG&E/Bechtel Generating Company
7475 Wisconsin Avenue
Bethesda, MD 20814

Dear Steve:

This letter is to confirm our interest in supplying coal to the Indiantown Cogeneration Project being developed by your firm. In a preliminary proposal, we indicated our interest in supplying all of the project's coal requirements, anticipated to be approximately 1,250,000 net tons per year, from our Powell Mountain Coal Company operations located in Lee County, Virginia and Harlan County, Kentucky. Sufficient reserves of acceptable quality coal are in place there to supply this quantity of fuel for the 20-year term we have discussed.

Further, we understand that you will require ash disposal services for boiler ash and scrubber by-products, and are proceeding with the preliminary activities necessary to provide this service at our mine. Of course, final details will be established as we finalize of supply/disposal agreement.

Steve, we look forward to continuing to work with you on the Indiantown Cogeneration Project. Please feel free to call me whenever I can be of assistance.

Sincerely,

Dayton E. Eisel, III

DEE:dmk

QUESTION 47

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

The applicant has proposed to dispose of all solid wastes generated at offsite locations (Table 3.7.1-1 and Section 3.7.1.2). Our main concern is disposal of bottom and fly ash at the as yet unidentified mine where the coal will come from. In order to provide reasonable assurance of proper disposal, the applicant should provide a copy of a contract or a long term agreement demonstrating that the ash will be accepted for disposal at the mine site.

RESPONSE

The ICL intends to finalize its coal supply/ash disposal agreement by early 1992. See the letters attached to the response for FDER Question 46, in which several bidders express their willingness to provide ash disposal services for the project.

QUESTION 48

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

The paragraphs discuss the fact that individual subcontractors will be responsible for handling hazardous wastes resulting from their onsite activities. Our experience with contractor activities shows that a signficiant amount of oversight by the site owner is needed to make certain that raw materials are stored and handled properly and waste materials are properly managed and transported to disposal facilities. ICL should also have in place procedures to follow for subcontractor reporting of potential discharges of hazardous materials/wastes. Quick identification by all parties during all phases of construction (as well as plant operation) of actual or potential contaminant releases clearly is preferable to long-term assessments/cleanups later. Examples include the requirements for subcontractors to provide secondary containment surrounding portable fuel tanks; storing paint related materials and solvents in secure areas designed to contain spills; having emergency plans in place in order to prevent the possibility of fires in ignitable storage areas and provide for quick response to these incidents. Waste analysis plans are needed.

RESPONSE

Construction

The prime contractor has developed procedures for storage and handling of all hazardous materials onsite, as well as an emergency response procedure. These procedures are the same or equivalent to those presented in the Hazardous Waste Management Plan, found in the response to SFWMD Question 11. The procedures for storage and handling require that all materials be stored in areas that have secondary containments designed to contain spills. The emergency response procedure requires prompt notification of the prime contractor, who then will promptly notify the owner and all appropriate authorities, in the event of any significant spill. In addition, this procedure identifies the appropriate response for each category of spill, including direct actions required to mitigate spill consequences.

These procedures apply to all hazardous materials of the prime contractor and all subcontractors. The owner will perform periodic audits to verify that the contractor is complying with his procedures. In addition, periodic drills will be conducted to verify that all site personnel are properly trained in responding to spills.

Operations

The above-mentioned Hazardous Waste Management Plan establishes procedures for the storage and handling of hazardous materials, as well as an emergency response procedure. All hazardous materials will be stored in areas that have secondary containments designed to contain spills. The emergency response procedure will require prompt notification of owner's management and appropriate authorities having jurisdiction. Periodic audits and drills will be performed to verify that personnel are properly trained to implement these procedures.

Should it become necessary, either during construction or operations, to dispose of material from a spill of unknown source, the material will be analyzed prior to disposal so that the appropriate disposal method may be selected.

QUESTION 49

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

Waste oil disposal may not be as easy as "collected in appropriate containers and transported offsite for recycling or disposal at an approved facility." Testing is needed of used oil prior to determining disposal in most cases. We suggest that individual waste streams be clearly segregated. For example: Dedicating certain drums for "waste mineral spirits", "used lubricating oil", "hazardous waste lacquer thinner", or similar lawful language. Such easy designations help prevent the mixing of incompatible wastes. This clarification also would help in profiling the wastes in order to determine the proper disposal or recycle. Routine maintenance of construction vehicles and refueling of vehicles should be conducted on impervious surfaces (e.g. on concrete pads with containment and provisions for separating spills etc. from rain water).

RESPONSE

Disposal of hazardous and potentially hazardous materials, including waste oil, is addressed in the Hazardous Waste Management Plan provided in response to SFWMD Question 11.

Waste Oil Disposal

Consistent with FDER suggestions, waste oil and other hazardous materials will be segregated into individual waste streams and collected in containers that are clearly identified for a specific product or group of compatible products. These containers will then be collected for recycle or disposal, as appropriate, by contractors at approved facilities. Any substances of unidentified origin will be analyzed and identified prior to disposal at an approved facility.

Vehicle Refueling and Maintenance

During construction and operation, all mobile vehicles, except for large construction cranes, large earth-moving equipment, etc., will be refueled and maintained in facilities that have impervious surfaces and containment to provide separation from storm runoff. Refueling and maintenance of vehicles at other locations will be performed by personnel who have been trained in spill prevention control and containment.

QUESTION 50

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

It needs to be clear that ultimate responsibility for proper management of wastes generated at the site are with the site owner.

RESPONSE

As the owner, ICL has the ultimate responsibility for the proper management of wastes generated at the facility, is taking a pro-active role in the management of these processes. Steps taken by ICL include reviewing and implementing procedures for waste handling and disposal to verify that these procedures comply with regulatory requirements, auditing records of those responsible for disposal, and conducting drills and other tests to verify that personnel are properly trained and perform their roles appropriately.

QUESTION 51

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling

Over the past two years, we have logged in several incidents involving the discharge of diesel from locomotive fuel tanks. While we have no record of diesel discharges along this segment of the railroad corridor, it is conceivable that, over the years, spills have occurred to the rail track/bed. Provisions should be made to address cleanup in the event contamination is discovered along the tracks during the pipeline construction part of the project.

RESPONSE

The applicant will prepare a contingency plan addressing contamination responses in the event contamination is discovered during pipeline construction. If soil contamination is discovered during pipeline construction, ICL or its contractor will notify the appropriate agencies and work with FDER to ensure containment of the contaminants.

QUESTION 52

The US EPA and the Department are currently tracking the cleanup of a nearby site known as Florida Steel. The site is a Superfund site, contaminated with hazardous wastes from past operations. Close coordination needs to be made with the Bureau of Waste Cleanup, the US EPA, Florida Steel and the SED to make certain that possible cleanup alternatives at Florida Steel take into account the ICL plant. Also, work needs to be conducted documenting any possible effects on existing contamination at Florida Steel (e.g. ground water contamination plumes or proposed cleanups). It is recommended that this coordination be conducted soon, so that there is ample lead time for project changes and considerations for the Florida Steel cleanup.

Source: February 28, 1991, Letter from S. L. Palmer to D. K. Kiesling.

RESPONSE

ICL is aware of the existence of the Superfund Site at the adjacent Florida Steel site. Discussions and coordination with EPA have occurred and will continue as our project proceeds and as the site cleanup activities continue. Modelling of groundwater withdrawals for dewatering during construction demonstrates that there is no effect on the movement of the contamination plume on the Florida Steel site. See response to SFWMD Question 37.

HOPPING BOYD GREEN & SAMS

ATTORNEYS AND COUNSELORS
123 SOUTH CALHOUN STREET
POST OFFICE BOX 6526
TALLAHASSEE, FLORIDA 32314
(904) 222-7500
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DOUGLAS S. ROBERTS
JULIE B. ROME
KRISTIN C. RUBIN
CECELIA C. SMITH

OF COUNSEL
W. ROBERT FOKES

April 20, 1992

RECEIVED
APR 22 1992
Division of Air Resources Management

RECEIVED
APR 20 1992
D. E. R.
SITING COORDINATION

Hamilton S. Oven, P.E.
Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399

Re: Proposed Modification to Certification for Indiantown Cogeneration Project

Dear Buck ~~Mr. Oven~~:

On behalf of Indiantown Cogeneration, L.P. (ICL), I am submitting both to the Department of Environmental Regulation (DER) and the parties to the original certification proceeding the enclosed requested modification of site certification of the Indiantown Cogeneration Project. The modification is submitted pursuant to Section 403.516(1)(b), Florida Statutes (F.S.), which allows DER to modify a certification where no objection is raised by a party or an affected member of the public. Agency parties have 45 days to submit written objections to the proposed modification. The public will have 30 days after public notice to raise written objections.

The attached modification consists of a Proposed Agreement for Modification of Site Certification, proposed Revised/Additional Conditions of Certification and a report providing details on the proposed modifications. This submittal is in accordance with the provisions of Rule 17-17.211, Florida Administrative Code (F.A.C.).

Pursuant to your request, ten copies of the proposed modification are being submitted to DER for its use and review. By copy of this letter, ICL is also submitting the modification to the parties and persons on the attached list. The number of copies provided to each party is also indicated. Additional copies are available upon request.

ICL requests that DER publish in the Florida Administrative Weekly a public notice of this modification. That notice will commence the period for public comment. ICL will publish a notice of this modification in the Indiantown News. Copies of the requested modification will be made available at public locations.

A check in the amount of $10,000 payable to DER is enclosed. These funds will reimburse DER and agency parties for expenses incurred in reviewing this modification.

ICL is available to discuss this matter and to address any agency concerns or questions. We will contact the parties in the next several days to discuss this request.

Sincerely,

Douglas S. Roberts

Douglas S. Roberts

DSR/gs
Encls.

cc: Richard T. Donelan
Parties to Original Certification,
as shown on attached list

DISTRIBUTION LIST
INDIANTOWN COGENERATION PROJECT
REVISED SITE LAYOUT AND DESIGN SUBMITTAL

	No. Copies
Hamilton S. Oven, Jr., P.E. Florida Department of Environmental Regulation 2600 Blair Stone Road, Room 612 Tallahassee, FL 32399-2400 (904)487-0472	10
Richard T. Donelan, Esquire Assistant General Counsel Florida Department of Environmental Regulation 2600 Blair Stone Road, Room 668 Tallahassee, Florida 32399-2400 (904)488-9730	1
Kathryn Funchess Senior Attorney Florida Department of Community Affairs 2740 Centerview Drive Tallahassee, Florida 32399-2100 (904)488-0410	1
Paul Darst Florida Department of Community Affairs 2740 Centerview Drive Tallahassee, Florida 32399-2100 (904)488-4925	1

DISTRIBUTION LIST
INDIANTOWN COGENERATION PROJECT
REVISED SITE LAYOUT AND DESIGN SUBMITTAL

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Vernon Whittier Assistant General Counsel Department of Transportation Haydon Burns Building 605 Suwannee Street, M.S. #58 Tallahassee, Florida 32399 (904)488-6212	2
Cecile Ross South Florida Water Management District 3301 Gun Club Road West Palm Beach, Florida 33416-4680 (407)686-8800 - (800)432-2045	1
Susan M. Coughanour South Florida Water Management District 3301 Gun Club Road West Palm Beach, Florida 33416-4680 (407)686-8800 - (800)432-2045	5
Eugene McClellan Assistant General Counsel Department of Natural Resources 3900 Commonwealth Boulevard Tallahassee, Florida 32399 (904)488-9314	1
Roger G. Saberson Attorney for Treasure Coast Regional Planning Council 70 S.E. 4th Avenue Delray Beach, FL 33482-4514 (407)272-8616	1

DISTRIBUTION LIST
INDIANTOWN COGENERATION PROJECT
REVISED SITE LAYOUT AND DESIGN SUBMITTAL

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Fred W. Van Vonno Assistant County Attorney Martin County 2401 Southeast Monterey Road Stuart, Florida 34996 (407)288-5440	1
Mary McKinnon Senior Planner Martin County 2401 Southeast Monterey Road Stuart, Florida 34996 (407)288-5440	1
Brian Sodt Central Florida Regional Planning Council 409 E. Davidson Street Bartow, Florida 33830-2089 (813)534-7130	1
John D. Cassels, Jr. Counsel for Okeechoee County 400 Northwest Second Street Okeechobee, Florida 34972 (813)763-3131	1

DISTRIBUTION LIST
INDIANTOWN COGENERATION PROJECT
REVISED SITE LAYOUT AND DESIGN SUBMITTAL

	No. Copies
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Doug Roberts Hopping Boyd Green & Sams 123 South Calhoun Street Tallahassee, Florida 32314 (904)222-7500	3

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

IN RE: INDIANTOWN COGENERATION PROJECT POWER PLANT SITE CERTIFICATION, INDIANTOWN COGENERATION, L.P.,	DER CASE NO. PA 90-31

PROPOSED AGREEMENT FOR MODIFICATION OF SITE CERTIFICATION, INCLUDING CONDITIONS OF CERTIFICATION

I

Indiantown Cogeneration L.P., (ICL) hereby requests a modification of the certification, including conditions of certification, for the ICL Indiantown Cogeneration Project (Project) pursuant to Section 403.516(1)(b), Florida Statutes (F.S.) and Rule 17-17.211, Florida Administrative Code (F.A.C.). Those provisions authorize the Department of Environmental Regulation (DER) to modify the certification after public notice and opportunity for review by the parties to the original certification proceeding and upon no objection being raised by these persons. In support of this modification, ICL states:

II

On February 6, 1992, ICL was issued a Site Certification Order by the Siting Board, pursuant to Chapter 403, Part II, F.S., authorizing the construction and operation of the Indiantown Cogeneration Project and associated linear facilities, subject to the provisions of the certification and conditions of certification.

Subsequent to the certification hearing and the issuance of the certification, Project design and discussions with the Project's steam host, bulk commodity suppliers, and major equipment vendors have identified a number of modifications to the certification which are required. The proposed modifications are described below with greater detail provided in an appended report on the design and site layout modifications. The proposed modifications will result in few, if any, increased environmental impacts over those anticipated in the original Project design.

III

Proposed Modifications

A. Alternate Rail Spur Corridors.

In the initial Site Certification Application, and in the certification proceedings, rail delivery of coal to the site was proposed to be accomplished by construction of a rail spur from the CSX Railroad across the Florida Steel site into the Project site. ICL is now proposing to obtain approval for two alternate rail spurs to connect the site to the CSX Railroad. The two alternative spurs are shown on Revised Drawings COA 0001A and COA 0001B included in the description of modifications submitted in support of this Agreement. The two alternate rail spurs will allow ICL flexibility in selecting the most appropriate corridor among the three alternatives. The alternate rail corridors will be subject to the attached revised/additional conditions of certification as well as the previously adopted conditions to the extent not modified by this agreement.

B. <u>Alterations to Plant Facilities</u>

ICL has identified the need to change or increase the size and dimensions of various on-site facilities. ICL proposes increasing the size of the covered coal storage building to increase the capacity of the active coal storage from the original seven-day capacity to approximately a ten-day supply of coal.

ICL also proposes increasing the size of the on-site ash storage silos. Ash is stored here before being loaded into rail cars for removal from the site. The environmental protection and control measures for the original design of the coal storage and ash storage facilities will be maintained and increased, as necessary, to achieve the same level of protection. These facilities shall conform to the applicable conditions of certification in the Certification Order.

ICL proposes to reconfigure the plant's maintenance, warehouse and administration building. The original two story building is now proposed to be a single story building with an appropriately enlarged building footprint. ICL has also requested approval to construct a visitors' center/administration building near the entrance to the Project site. ICL also proposes to enlarge the on-site electrical transmission switchyard.

The changes to the coal storage building, the ash storage silo, the maintenance/warehouse building, the new visitor center/administration building and the transmission switchyard, as shown on the revised drawings submitted in support of these modifications, are approved.

C. Alternative Nitrogen Oxide Controls.

ICL proposes that the certification order and the appropriate conditions of certification be modified to approve selective catalytic reduction (SCR) as an alternative emission control technology for nitrogen oxides (NOx). The certification order discussed selective non-catalytic reduction (SNCR) and low NOx burners as the selected control technology for NOx. The recently issued PSD permit contemplates that SCR may be required, if needed, to meet the NOx emission limits established in the Certification Order and the PSD Permit. ICL therefore proposes that the certification be modified to approve SCR as an alternate NOx control technology to meet the emission limits. The modified portions of the certification discussing emission control technologies and the revised Conditions of Certification attached to this Agreement are approved.

D. Option To Use Two 50%-Capacity Auxiliary Boilers.

The adopted conditions of certification approve the construction and operation of a single auxiliary boiler. That boiler is used during plant startup and as a backup source of steam for the adjacent Caulkins Citrus Plant during periods when the Project's main boiler is not operating. To provide greater reliability of steam supply both to the main boiler during startup and to the adjacent citrus plant, ICL proposes that the certification be modified to allow construction and operation of two auxiliary boilers, each with a maximum capacity of 50% of the original auxiliary boiler. The two auxiliary boilers combined would not exceed the maximum heat input rate and the established emission rates for the auxiliary boiler set in the conditions of certification. The proposed modification would provide flexibility to use two auxiliary boilers instead of one if ICL elects to install two auxiliary boilers instead of one. There shall be no increase over the limits established in the conditions of certification for total heat input, total emissions, or hours of operation on various fuels with the use of two boilers.

E. On-site Storage of Diesel and Propane.

Propane, an approved backup fuel to the main and auxiliary boiler, was originally proposed to be delivered to the site by pipeline from the gas company serving the Project area. However, to ensure greater fuel supply reliability, ICL proposes that the site certification be modified to allow the construction and operation of an on-site propane storage tank. The details of this storage tank are provided in the descriptions of modification submitted in support of this requested modification.

Additionally, ICL requests that the certification be modified to include approval for an on-site diesel storage tank. This above-ground tank, to be located in an appropriate containment area, will provide fuel to the on-site rail locomotive. ICL requests that the certification order be modified to include approval for on-site storage of propane and diesel. Such storage shall be undertaken in compliance with the conditions of certification in the Certification Order and subject to the additional conditions set forth in the attached Revised/ Additional Conditions of Certification.

F. Revisions to Perimeter and Site Access Roads.

ICL proposes that the certification be modified to reflect a relocation of the new County Road to be built as part of the project to provide access to the site. The road is to be relocated in the southwest corner of the site to provide a larger buffer to an adjacent wetland. ICL also requests approval for a redesign of its site access road to delete the interior bridge over the railroad and to reconfigure the access road based upon the alternative rail spurs that will serve the site, as discussed above. These modifications described in further detail in the description of modifications submitted in support of this Agreement, are approved.

Request For Relief

Accordingly, ICL requests that

1. All parties to the original certification proceeding agree to, or otherwise do not object to, this proposed modification and the attached revised and additional provisions of the certification and the conditions of certification within thirty (30) days of submittal of this proposed Agreement, as provided for in Section 403.516(1)(b), F.S.

2. Upon no objection being raised by the parties as provided above or by a substantially affected person within forty-five (45) days of public notice of this proposed modification, the Department of Environmental Regulation issue an order modifying the terms and conditions of the certification, pursuant to Section 403.516(1)(b), F.S.

3. That the Department of Environmental Regulation grant such other relief as may be appropriate, including necessary conditions of certification and modifications to the Certification Order.

Respectfully submitted this 20th day of April, 1992.

HOPPING BOYD GREEN & SAMS

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail, hand delivery or Federal Express this 20th day of April, 1992:

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April, 1992

INDIANTOWN COGENERATION PROJECT

Revised/Additional Conditions of Certification

A. Alternate Railroad Spur Corridors.

1. Paragraph 4, page 5 of the Certification Order is revised to read:

   4. Features of the project include a rail spur to be constructed in one of three alternate rail spur corridors to connect the site to the existing CSX rail line, . . .

2. Part II(2), Wetlands, page 21 of the DER Conditions -- create a new paragraph K. to read:

   K. The provisions of Condition II(2) are also applicable to wetlands located along the alternate rail corridors connecting the site to the CSX Railroad.

3. Part VI, page 59 of the Department of Transportation Conditions -- create paragraph 8 to read:

   8. The permittee shall obtain approval from the Department of Transportation, pursuant to Rule 14-46.003(2), F.A.C., for any public railroad-highway grade crossings associated with the rail spur the permittee selects to connect the Project Site to the CSX Railroad.

4. Part IV, C, 1, page 42 of the SFWMD Conditions - create paragraph k. to read:

   k. In the event the rail spur selected by the permittee impacts the surface water management system of an existing legal user, the permittee shall be responsible for correcting any water quality or water quantity problems resulting from the selected rail spur. Detailed plans and supporting calculations shall be submitted to SFWMD pursuant to Condition IV, C, 3., a.(3).

B. 1. Alterations to Plant Facilities

No new or revised conditions of certification are required to address the modifications in site layout and building sizes and dimensions.

The revised site layout, as shown on Drawings COA0001A and COA0001B, is approved.

C. Approval of SCR as Option to Control NOx.

1. Paragraph 12, page 10 of the Certification Order - insert at end of existing paragraph 12:

   12. . . .As required to achieve the emission limits for nitrogen oxides established in the conditions of certification, ICL may use selective catalytic reduction to control nitrogen oxides.

2. Paragraph 51, page 23 of the Certification Order - insert at end of existing paragraph 51:

   51. . . .As an alternative, selective catalytic reduction may be used to achieve the established emission limits for nitrogen oxides.

D. Optional use of 2 auxiliary boilers:

1. Paragraph 16, page 11 of the Certification Order is revised to read:

   16. The ICP will also include ~~an~~ up to two auxiliary boilers which will serve two functions. . . .

2. Paragraph 53, page 24 of the Certification Order is revised to read:

   53. For the auxiliary boilers, the BACT analysis concluded that the . . . .

3. Condition II(1), B.1., page 10 of the Conditions of Certification is revised to read:

   1. Boilers
   The Pulverized Coal (PC) boiler is permitted to operate at a maximum of 3422 MMBtu/hr heat input (nominal 330 MW). This facility shall be allowed to operate continuously (8,760 hrs/yr). In addition to the PC boiler, the facility will have one or two auxiliary boilers rated at up to a combined total of 342 MMBtu/hr (#2 Fuel Oil) and a combined total of 358 MMBtu/hr (Natural Gas or Propane) which operate at the combined total heat input rate

a maximum of 5,000 hours with up to 1000 hrs/hr on #2 Fuel Oil and the balance on natural gas or propane.

4. Condition II(1), B.2.b., page 11 is revised to read:

   b. Auxiliary Boiler
   The auxiliary boiler or boilers, rated at up to a combined total of 358 MMBtu/hr (Natural Gas and propane) and a combined total of 342 MMBtu/hr (#2 Fuel Oil), shall be limited to a maximum of 5000 hours/year at the combined total heat input rates with up to 1000 hrs/yr firing #2 fuel oil with 0.05% sulfur, by weight, and the balance firing natural gas or propane. The maximum total annual emissions from the auxiliary boiler or boilers will be as follows when firing #2 fuel oil:

E. Diesel and Propane Storage.

1. Paragraph 32, page 16 of the Certification Order -- insert at end of existing paragraph:

   Propane may be used as an alternate backup fuel to natural gas. Propane will be stored in on-site tanks.

2. Paragraph 33, page 16 of the Certification Order -- insert at end of existing paragraph:

   Diesel fuel will also be used to fuel on-site locomotives which move rail cars around the site. Diesel fuel will also be delivered by truck and stored in on-site storage tanks designed in accordance with FDER regulations.

F. Revisions to Perimeter and Site Access Roads.

1. No revisions to the certification, including the Conditions of Certification, are required. Approval is requested of the revised site layout as shown on Figures COA0001A and COA0001B attached to the modification submittal.

Indiantown Cogeneration Project
Design and Site Layout Modifications

April 17, 1992

Prepared for: Florida Department of Environmental Regulation
Prepared by: Indiantown Cogeneration, L.P.

Indiantown Cogeneration Project
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Introduction

Indiantown Cogeneration, L.P. (ICL) seeks agency approval of minor modifications to the site layout and design of the Indiantown Cogeneration Project (ICP), which have been identified during the detailed design stage of the project. Each change is discussed below in the context of the original Site Certification Application (SCA).

1. Alternative Railroad Access Routes

Section 3.2 (Volume 1) of the SCA described the construction of a new rail spur providing access from the existing CSX railroad to the site. The spur is shown on Figure 3.1-1 of the SCA and crosses a site owned by Florida Steel Corporation. ICL is now seeking approval of two alternate railroad access routes to the ICP site. Depending on the outcome of negotiations with landowners and regulatory agencies over the alternate routes, ICL would construct one of the three routes. Under all scenarios, the water pipeline from Taylor Creek/Nubbin Slough would be routed from the CSX ROW into the ICP site either within the corridor for the new County Road, or within the rail spur corridor. Final drawings will include the routing of the water pipeline.

The enclosed Drawings COA 0001A, COA 0001B, COA 0003, COA 0091, and COA 0092, which are revised Site Plans and cross sections, illustrate conceptual construction methods and design for each alternative. The two alternatives are described below.

A. Caulkins Alternative

This alternative route is illustrated on the revised site layout (Drawing COA 0001A), attached. The rail spur would parallel the new County Road from the intersection with the CSX railroad and enter the ICP site at the northwest corner. The rail line will permanently occupy approximately 2 acres of land. Construction of the rail will require an additional 30 feet of corridor width, which will be used as a drainage swale along the eastern edge of the rail bed, once construction is completed.

In this alternative, the new County Road to be built by ICL has been redesigned to share a common drainage system with the rail line. The original road corridor width was 80 feet. Road and railroad with drainage system will occupy a 105-foot wide, 2,000-foot long corridor.

Wetlands. On April 13, 1992 a field visit was conducted by Jim Poppleton, Wetlands Ecologist, ECT, who prepared the ecology sections of the SCA and Sufficiency Responses and provided expert testimony at the Site Certification

Hearing. The purpose of the visit was to identify wetlands within the wider combined road/rail corridor.

Mr. Poppleton noted the following wetlands and potential wetlands within and adjacent to the road/rail corridor:

- The rail spur crosses an intermittent ditch parallel to and south of the CSX railroad. The ditch is connected to waters of the U.S. and, most likely, waters of the state.

- The road/rail corridor would overlap an existing north-south drainage ditch on the western edge of the Caulkins property. This ditch is not connected to waters of the U.S. or state.

- Immediately north of where the new County Road/railroad corridor enters the ICP site, it crosses a narrow wetland connecting two isolated wetlands (Wetland 5 on the ICP site and an unnumbered wetland to the southwest).

ICL plans to span the ditch parallel to CSX as well as the hydrologic connection between the wetlands, avoiding impacts to any wetlands within this alternate corridor. ICL proposes to submit a detailed impacts analysis to DER, SFWMD and Martin County as a post-certification submittal, consistent with Conditions of Certification II.2 and IV.3.

Upland Preserves. In order to accommodate the required turning radius as the rail enters the ICP site, the rail loop has been reconfigured and bisects a portion of the northern upland preserve. In compensation, additional upland preserve acreage has been designated south of Wetland 5, increasing the buffer to that wetland. The original total upland preserve acreage of 59 acres has been retained.

Stormwater management. The drainage swale system for the combined corridor for the new County Road and the ICP rail spur has been sized to provide detention for stormwater runoff quality and quantity control. An existing drainage ditch along the western edge of the Caulkins site will be relocated to accommodate existing stormwater runoff from part of the Caulkins site. Thus, there will be no changes in postconstruction stormwater runoff patterns from or to adjacent lands. Revised calculations supporting the design basis will be provided as necessary in the final post certification submittal for the surface water management system, consistent with Conditions of Certification IVC.3.a(3) and b.

Traffic Analysis. Figure 1 illustrates the intersection between the new County Road and SR 710, as designed for this alternative. Doug Coomer, Transportation Engineer, Kimley Horn, conducted the traffic analyses of the project for the SCA and Sufficiency Responses. He has analyzed the impacts of this proposed alternative and concluded that no increase or change in impacts to rail or vehicular traffic is expected as a result of constructing this alternative (see attached report, Appendix A).

Since the alignment requires that the new County Road be closed for the coal train at a location close to SR 710, a detailed analysis of vehicle queuing at this closure was performed, assuming that the mainline crossing gates would not be closed during the spur line operation across the new County Road. Based upon the worst-case analysis, the available vehicular storage is adequate to accommodate queuing traffic resulting from this proposed alignment. The secondary access road to the ICP site from West Farms Road would provide emergency access in the event a train blocks the railroad crossing.

ICL will obtain the necessary approvals for the railroad public road crossing in this corridor.

B. Tampa Farms Service Alternative. Revised Drawing COA 0001B shows this alternate railroad spur route, which connects the CSX rail line to the ICP site through the Tampa Farms site, entering the ICP site at the northwest corner. The railroad would occupy a 100' wide construction corridor and up to a 10-foot wide permanent corridor (the rail spur at spans over wetlands will be approximately 30 feet wide). The 3,500-foot long line would permanently occupy approximately eight acres.

Wetlands. On April 13, 1992 a field visit was conducted by Jim Poppleton, Wetlands Ecologist, ECT, who prepared the ecology sections of the SCA and Sufficiency Responses and provided expert testimony at the Site Certification Hearing. The purpose of the visit was to identify wetlands within the proposed rail corridor.

Mr. Poppleton noted the following wetlands and potential wetlands within and adjacent to this corridor:

- The rail spur crosses a ditch parallel to and south of the CSX railroad. The ditch is connected to waters of the U.S. and, most likely, waters of the state.

- The rail corridor crosses the toe of an isolated marsh on the Tampa Farms property.

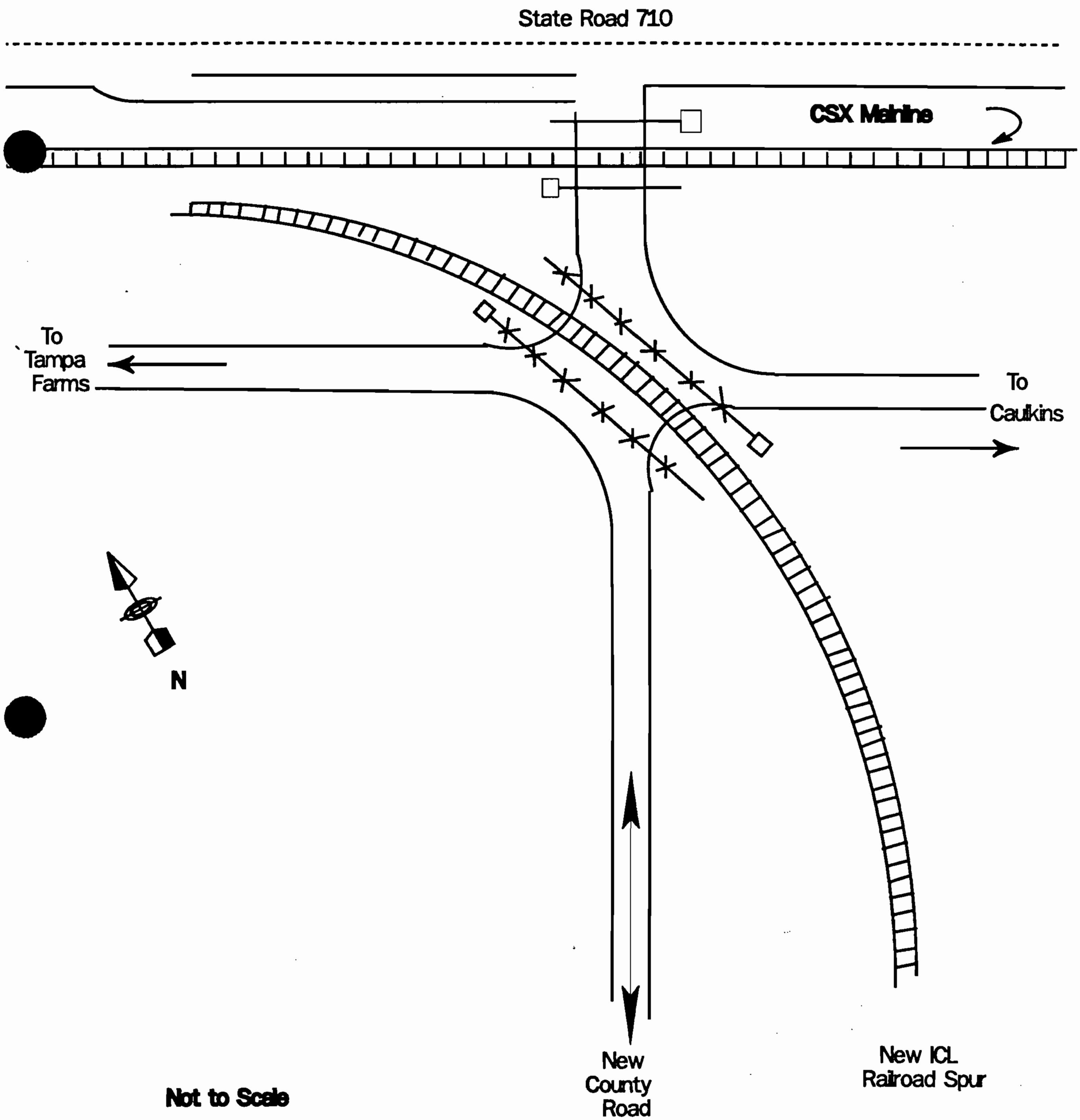

Figure 1 : Conceptual Design: Caulkins Alternative Intersection with SR710

- The rail corridor continues to the south and traverses a 20 x 1,400-foot long depression created by clearing, adjacent to the eastern boundary of the Tampa Farms property. Though historically an upland, the clearing and subsequent lowering of elevation by three to six inches has created an environment favorable to wetland plants. Vegetation sampling would be required to determine if fifty percent of the dominant species are upland plants.

- Immediately southeast of where the proposed railroad corridor crosses the new County Road and enters the ICP site, it crosses a narrow wetland connecting two isolated wetlands (Wetland 5 on the ICP site and an unnumbered wetland to the southwest).

ICL plans to span the ditch parallel to CSX, the toe of the isolated marsh on the Tampa Farms property, and the hydrologic connection between the wetlands, avoiding impacts to those wetlands. If the depression is determined to be a wetland, ICL will reroute the rail spur through adjacent uplands to avoid impacting the wetland. ICL proposes to submit a detailed impacts analysis to DER, SFWMD and Martin County as a post-certification submittal, consistent with Conditions of Certification II.2 and IV.3.

Upland Preserves. In order to accommodate the required turning radius as the rail enters the ICP site, the rail loop has been reconfigured and bisects a portion of the northern upland preserve. In compensation, additional upland preserve acreage has been designated south of Wetland 5, increasing the buffer to that wetland. The original total upland preserve acreage of 59 acres has been retained.

Stormwater management. The drainage swale system for the rail spur has been sized to provide detention for stormwater runoff quality and quantity control. There will be no change in post-construction runoff patterns from or to adjacent lands. As necessary, revised calculations supporting the design basis will be provided in the final post certification submittal for the surface water management system, consistent with Conditions IV C.3a(3) and b.

Traffic analysis. No increase or change in impacts to traffic is expected as a result of this alternative (see Appendix A). The alignment provides adequate storage for queuing vehicles, and the secondary access to the ICP site from West Farms Road would provide emergency access in the event a train blocks the railroad crossing of the new County road.

ICL will obtain the necessary approvals for the railroad-public road crossing as a post-certification activity.

2. Redesigned main access road; additional rail trackage

The SCA proposed that the main access road into the site from the County Road include an on-site bridge over the railroad track, inside the ICP site, to permit uninterrupted access to the site. Upon further analysis of rail operations management options, ICL determined that blockage of the access road would not be an issue. Additional operational flexibility would be achieved with the addition of double trackage (as shown on Revised Drawings COA 0001A and B). This will provide sufficient storage to contain a full complement of rail cars onsite without blocking the access road. In addition, the secondary access road will provide secondary emergency access during rail deliveries averaging three days a week, which would block the main access road for up to five minutes.

The main access road has been redesigned with an onsite, private at-grade crossing, and relocated south of the rail loop. Detailed drawings of the road, including drainage system, will be submitted as part of the post-certification submittal as required by Condition of Certification IVC.3a(3).

With the planned rail operations management, the access road will provide adequate vehicular storage for the peak number of 40 workers.

3. Relocation of county road in southeast corner of ICP site

During continuing design of the new County road, it became apparent that repositioning the portion of the road south of Wetland 1 further to the south by 50 feet would provide a larger buffer to the wetland and would also make use of previously disturbed areas along the existing dirt road. Revised Drawings COA 0001A and B show the relocated road, with the original site boundary.

No changes to the road's design, construction, stormwater management or other features would be required. The final stormwater management plan for this road will be submitted to SFWMD as provided in Condition of Certification IVC.3b.

4. Increased size of coal storage building

The original coal storage building was designed to accommodate a 7-day supply of coal (see Section 3.3.1.2 of the SCA). ICL has determined that approximately three additional days of coal supply are required onsite to provide operating flexibility. ICL proposes to increase the length of the coal storage building by approximately 150 feet, adding some 8,000 tons of storage capacity. The coal storage handling system is illustrated in Figure 4-2 of the PSD permit application, found in Section 10.1 of the SCA. The proposed resizing would result in one change to this Figure; the active coal storage pile would increase from 24,000 tons to approximately 32,000 tons.

All other design elements of the coal storage building, including stormwater management, installation of a concrete liner, and installation of particulate control systems, will be revised to accommodate the increased size. However, the same design and regulatory requirements will be achieved as with the original design for these features.

Appendix B presents a report from Ping Wan, Air Quality Impact Expert, Bechtel Power Corporation, analyzing the impacts of this proposed redesign to modeling and fugitive dust emissions. Increased length of the coal storage building will not affect any of the modeling parameters or conclusions. Table 4-3 of the PSD Permit in Section 10.1 of the SCA presents fugitive emission projections for the coal handling system. No data in this table will be changed as a result of this modification. The particulate emission limits for this building set forth in Specific Condition 9 of the PSD permit will be achieved.

The redesign of the coal storage building will not affect any preserve areas. The final stormwater management plan will be modified to accommodate the increased roof runoff, which will be captured in Stormwater Basin 3 for eventual discharge into Wetland 4, as originally designed. The basin area will be modified to maintain the allowable discharges stated in the Condition of Certification IVC.2a.

5. Increased size of ash storage silo

The ash storage silo was originally designed to hold three days of ash in temporary storage on site, before removal for reuse or disposal (see Section 3.7.1.2 of the SCA). In order to provide operating flexibility, ICL requests increased capacity for approximately nine days of ash storage. This will be accomplished by increasing the diameter of the silo from 50 to 55 feet and the height from 120 to 185 feet.

The ash storage silo is shown on Revised Drawings COA 0001A and B, the revised Site Layouts for each rail spur alternative. The baghouse for particulate control will be resized to accommodate the larger size of the building. The five foot increase in diameter will not produce measurable effects on stormwater runoff characteristics. All current requirements of the certification will be met by this design change.

Appendix B includes an air quality impact analysis of this proposed change. Table 4-3 of the PSD permit in Section 10.1 of the SCA presents fugitive emission projections for the ash handling system. All emission limits for ash storage and handling set forth in Specific Conditions 11 and 12 of the PSD permit will be achieved.

6. Approval of option to substitute two 50% auxiliary boilers for original single auxiliary boiler

The ICP site certification permits a single auxiliary boiler, which is described in Sections 3.1.2 and 3.3.5 of the SCA. In order to assure reliability of steam supply to the adjacent steam host, the single auxiliary boiler may have to be replaced with two half-sized boilers. This will protect fifty percent of the steam supply to the steam host and to the main boiler during startup in the event one of the auxiliary boilers is out of service. ICL requests approval to construct this alternate system, should it prove necessary.

Under either auxiliary boiler scenario, the stack height for the combined boilers would increase from 90 feet to 200 feet. This change will reduce air quality impacts, according to Ping Wan, Air Quality Impact Expert, Bechtel Power Corporation (see report, Appendix B).

Revised Drawings COA 0001A and B show the location of the auxiliary boilers, which would vent to a single stack. The emission controls proposed for the original auxiliary boiler (low NO_x burners for NO_x; firing of low sulfur (0.05%) oil for SO_2; combustion controls for CO and VOC's; and use of high quality fuel to limit particulate emissions; all as described in Section 3.4, Volume 2 of the SCA and the April Sufficiency Responses [DER 36, 37, 39, 42, and 44]), would be retained in the redesign of the auxiliary boiler.

With the exception of the increased stack height, stack parameter input data presented in the PSD permit application (Table 4-2 in Section 10.1 of the SCA) have not changed.

BACT Analysis. Appendix C is a letter from Steve Jelinek, Air Quality Engineer, ENSR (who prepared the original BACT analysis), stating that a reconfiguration to two fifty percent capacity auxiliary boilers would not affect the conclusions of the BACT analysis in the SCA (based on emissions data provided in Table 3.4.1-1 of the SCA).

Modeling. The proposed modifications to the auxiliary boiler system -- increased stack height and dual fifty percent boilers -- are predicted to reduce ground level emissions impacts associated with the auxiliary boiler. Additional dispersion modeling confirms this hypothesis, as well as confirming that auxiliary-main boiler interactions under this scenario will not cause greater air quality impacts (see Appendix B).

The model employed the same meteorological data and atmospheric modeling strategy used in the original PSD modeling effort. Full load and partial load auxiliary boiler operating scenarios, as well as the auxiliary-main boiler interactions, were evaluated.

The modeling results indicated that the redesigned auxiliary boiler system, when compared to the original system described in the PSD application, produces lower ground level pollutant impacts when operating alone or with the main boiler. Table 1 presents the modeled emission levels for the reconfigured auxiliary boilers at half and full loads, vs the PSD-permitted emission levels for the original single auxiliary boiler. In all cases, the combined emission rates for the auxiliary boilers are below PSD-permitted levels.

No changes to the conditions of certification are required, except to recognize that there will be two auxiliary boilers with 342 MMBtu/Hr (No. 2 fuel oil) and 358 MMBtu/Hr (natural gas and propane) maximum heat input, with combined total emissions limits as set in Conditions of Certification II(1)B.1 and II(1)B.2.b.

7. Approval of Option to Replace SNCR equipment with SCR

The SCA originally proposed installation of a selective non-catalytic reduction (SNCR) system to control NO_x emissions to the levels allowed in the PSD permit (see p. 3.1.2-2, Volume 1; and Appendix 10.1.2). The subsequently-issued PSD permit for the ICP provides that the emission limit for NO_x may be met using any technology; ICL is responsible to "apply whatever technologies [are] deemed necessary to ensure the NO_x limitation is met."

One of the possible NO_x control technology alternatives identified in the PSD permit is selective catalytic reduction (SCR). This technology was not approved as part of the initial certification; only low NO_x burners and SNCR were described in the certification order as being used at the site. ICL is therefore proposing that the certification be modified to approve the most appropriate technology, including specifically SCR, to meet the emission limit established in the PSD permit.

If utilized, the SCR system would employ a titanium oxide-based catalyst with vanadium pentoxide and tungsten oxide additives. The catalyst will be supplied by the boiler vendor; once it loses its reactivity, it will be returned to the vendor for refurbishing or disposal. No catalyst would be disposed of on-site.

8. Propane storage

Propane was proposed and approved as a back-up fuel to natural gas, for the auxiliary boiler and for the main boiler during light-off and warm-up (see

TABLE 1. ICL STACK SOURCES AT MAXIMUM IMPACT LOCATIONS
(AUXILIARY BOILERS AT 100 % LOAD)

Pollutant	Averaging Period	Aux. Boilers	New Total	Original Total
SO_2	3-Hour	17.2 (0.30,050)	23.2 (2.20,310)	24.7 (0.25,100)
	24-Hour	7.5 (0.25,330)	7.5 (0.25,330)	11.6 (0.25,110)
	Annual	0.94 (0.25,340)	0.94 (0.25,340)	1.15 (0.25,100)

(AUXILIARY BOILER AT 50 % LOAD)

Pollutant	Averaging Period	Aux. Boiler	New Total	Original Total
SO_2	3-Hour	6.1 (0.30,030)	22.7 (2.2,310)	24.7 (0.25,100)
	24-Hour	3.9 (0.25,350)	6.0 (3.2,310)	11.6 (0.25,110)
	Annual	0.62 (0.25,340)	0.64 (3.0,310)	1.15 (0.25,100)

Note: Concentrations are in $\mu g/m^3$.
Distance and direction shown are in km and degree, respectively, relative to the ICL main stack in parenthesis.
Total = Main Boiler + Auxiliary Boiler(s)

Condition of Certification II(1)B1). The original plan was to have the propane delivered to the site in the gas pipeline. During discussions with Indiantown Gas Company, it became apparent that insufficient storage capacity existed at the Gas Company to insure adequate supplies of propane.

ICL therefore proposes to construct two 30,000 gallon propane tanks on the site, to ensure reliable supplies of propane. The tanks will be located adjacent to and west of the main stack, as shown on Revised Drawings COA 0001A and B.

ICL has consulted the local fire marshall to design the tanks. In accordance with NFPA 58 (1989 edition), the propane tanks will maintain a minimum set back distance of at least 50 feet from the nearest building and a tank-to-tank separation of at least five feet. The tank location meets the minimum set back distances and separation criteria mandated by NFPA 58.

Fuel will be delivered by truck as needed to maintain adequate supplies for normal boiler start-up and operation. It will be pumped from the truck; all pipelines will be above ground.

9. Diesel storage

ICL proposes to provide on-site diesel fuel storage for fueling the yard rail engine which will move the rail cars while on site. ICP requests permission to construct a 1,000 gallon above ground tank, which will be sited between the main stack and the wastewater basin on the east side of the secondary exit road, as shown on Revised Drawings COA 0001A and B. Fuel will be delivered by truck approximately once a week.

The tank and fueling area will be located within bermed, imperviously lined areas sized to contain 110% of the tank capacity. Stormwater will be collected from the bermed area and pumped back to the plant for treatment and use, rather than being discharged into the stormwater management basins.

10. Reconfigured maintenance/warehouse/administration building

The maintenance, warehouse and operations building, shown on Revised Drawings COA 0001A and B, was originally designed as a two-story building. In order to improve efficiency of operations and construction, ICL now proposes to alter the design to a single story building. ICL also requests approval to construct a future visitor's center and administration building, to be located near the entrance to the site as shown on Revised Drawings COA 0001A and B.

Detailed plans for this building, including landscaping, will be submitted to Martin County at a later date.

The future visitor's center/administration building is not sited in any preserve area and will not impact any wetlands. Final post-certification submittals demonstrating that these modifications meet the required stormwater design criteria will be submitted to SFWMD, pursuant to Condition of Certification IVC.3.2e.

11. Increased size of switchyard

The SCA proposed construction of a switchyard to interconnect with the 220-kV Florida Power & Light (FPL) transmission line, which borders the northern property line. During design discussions with FPL, it was determined that a larger area would be required to accommodate the ring-bus system designed for the site. The proposed switchyard shown on Revised Drawings COA 0001A and B would occupy two acres, as opposed to the 1.25 acre site originally conceived.

The change in the switchyard area and the area around the cooling tower will result in an increase in runoff to the stormwater basins. In order to maintain the discharge from Basin 2 to Wetland 6 at the permitted limit stated in Condition of Certification IVC.2a, the drainage boundaries and basin areas of Basins 1 and 2 will be modified. This modification will not cause Basin 1 to discharge, consistent with the permitted design basis. The final stormwater management plan submitted to SFWMD as provided in Conditions of Certification IV C.2e and IVC.3 will include and address this change.

Appendix A

Letter from Doug Coomer, Kimley Horn

re: Traffic Analysis

Kimley-Horn

Kimley-Horn and Associates, Inc.
ENGINEERS • PLANNERS • SURVEYORS

4431 Embarcadero Drive West Palm Beach, Florida 33407 407 845-0665 Facsimile 407 863-8175

April 14, 1992
4241T.01(09)

Mr. G.K. "Chip" Allen
Project Engineer
U.S. Generating Company
7475 Wisconsin Avenue
Bethesda, Maryland 20814

Re: Indiantown Co-generation Project
Northwest of Indiantown
Martin County, Florida

Dear Chip:

As requested, we have conducted an evaluation of the two proposed railroad alignment alternatives associated with the proposed electrical power generation plant referenced above and located two miles west of Indiantown on the south side of State Road 710 in Martin County, Florida. The following presents the two alternatives and the findings of this evaluation.

<u>Alternative 1</u>

This alignment runs parallel to the planned new County road on the Caulkins Citrus Company site. A rail spur diverges from the mainline track west of the new County Road, would cross the road at an angle and then run parallel to it as it proceeds south to the site.

This alternative requires that the County Road be closed for the coal train at a location close to S.R. 710. The queuing of vehicles due to this closure was analyzed in detail. It was assumed in this analysis that the mainline crossing gates would not be closed during the spur line operation across the new County Road.

The analysis used 1990 A.M. peak hour turning movement counts grown to reflect 1995 projections. The highest peak 15 minute count was then added to the peak 15 minute project traffic. The total time of road closure for a 90-car train traveling at 10 mph was determined to be 365 seconds, including gate closure and opening time. If the train arrived during the peak 15 minute period, it was therefore concluded that a storage length of 13 vehicles would be required. At 25'/veh this is equivalent to 325'. This conservative approach assumes that the first vehicle stopped at the railroad crossing blocks the access to Caulkins. This is not necessarily true as vehicles going to the Caulkins Citrus Processing plan may not be affected by the crossing.

The new County Road provides 200' of storage length in advance of the proposed gated railroad crossing. Additional storage of approximately 400' for the proposed eastbound right-turn lane and 250' for the existing westbound left-turn lane should provide sufficient storage length. Hence, the proposed alignment should not cause queuing in excess of the storage available during the A.M. peak period.

<u>Alternative 2</u>

This alternative would run parallel first to the existing rail spur along the west side of Bay State Milling facility and then along the property line. It would then cross the new County Road into the proposed project.

No potential traffic problems are anticipated with this alignment. The railroad crossing is located 825' south of the intersection of S.R. 710 and the proposed new County Road. This distance provides enough storage for queuing vehicles during both the A.M. and P.M. peak periods.

The P.M peak hour will pose no problems as most vehicles will be exiting the plant and there is more than enough storage for queuing vehicles south of the crossing.

In the event of a train breaking down at the railroad crossing, the secondary access on West Farms Road can be used for both alternative alignments. This also provides a direct route to Indiantown. Access to Caulkins would continue to be available from S.R. 710 even with a breakdown on the crossing.

Our conclusion from the traffic analysis is that either alternative can operate successfully without causing vehicles queues greater than available storage. However, from a traffic operations perspective, the second alternative would operate better with less potential conflict in turning movements to other neighboring industrial facilities and less potential queuing impact upon S.R. 710.

If you should have any questions concerning this analysis or need additional assistance, please let me know.

Very truly yours,

KIMLEY-HORN AND ASSOCIATES, INC.

B. Douglas Coomer, P.E.
Senior Associate

BDC:jsl

4241T01-CA-L041492-bdc.wp

Appendix B

Report from Ping Wan, Bechtel Power Corporation

re: Air Quality Modeling and Impacts Analysis

April 17, 1992

AIR QUALITY IMPACT INVESTIGATION IN SUPPORT OF THE INDIANTOWN COGENERATION PROJECT DESIGN AND SITE LAYOUT MODIFICATIONS

Proposed Action:

Substitution of Two 50% Auxiliary Boilers for the Original Single Auxiliary Boiler

In order to insure reliability to the steam host, ICL proposes to replace the single auxiliary boiler with two boilers, each one-half the size of the original auxiliary boiler. This substitution will provide a minimum of 50% of the normal steam supply in the event that one of the reduced size boilers is out of service.

Findings:

The modeling methodology employed in the original PSD permit application was used to determine whether air quality impacts caused by the proposed substitution will exceed those presented in the original analysis. SO_2 impacts associated with the operation of the two auxiliary boilers were investigated; one stack for two boilers at full load (i.e., 100% capacity) and one stack for one boiler at full load (i.e., 50 % capacity). Impacts associated with air pollutants, other than SO_2, were estimated by taking the ratio of the specified pollutant emission rate to the SO_2 emission rate.

The GEP stack height for the ICL facility, reported in the original PSD permit application, was calculated at 500 feet. The main boiler stack will be constructed to 495 feet. For the substitution discussed here, the auxiliary boiler stack will be increased from 90 feet to 200 feet. Modeling results based on this substitution, and reflecting the increased auxiliary boiler stack height are summarized in Table 1. Results indicate that the full load case has higher ground-level concentrations than those estimated for the 50% load scenario, over all averaging time periods. The maximum impact areas are within 300 meters of the main boiler stack due to plume downwash conditions created by the boiler building. Modeling results also show that the maximum combined impacts (i.e., main boiler plus auxiliary boiler(s)) are less than the impacts reported in the original PSD application. Similar results are expected for the other air pollutants emitted.

In summary, the substitution of the original auxiliary boiler with two boilers, each one-half the size of the original auxiliary boiler, will result in impacts slightly lower than those presented in the original PSD application. No additional adverse effects to air quality, due to the proposed substitution, are expected.

Proposed Action:

Increased Size of the Coal Storage Building

The original coal storage building was designed to accommodate a seven-day supply of coal. Based on discussions with the coal supplier, ICL has determined that additional coal will be required to be stored on site in order to insure an adequate fuel supply to the facility. ICL has proposed to increase the length of the coal storage building by an additional 150 feet, thereby adding 8000 tons of storage capacity.

Findings:

The increase in length of the coal storage building by 150 feet will not affect either the GEP stack height determination nor the plume downwash calculations, because the controlling structure, which dictates the occurrence and extent of plume downwash, is still the boiler building, as reported in the original PSD application.

In spite of the increase in capacity of the active coal storage pile from 24,000 to 32,000 tons, the daily coal consumption by the ICL facility remains unchanged. Due to the fact that there will be no increase in the number of railroad cars per train load and that the load capacity per car remains unchanged, the number of hours of coal unloading activities per day at the ICL facility is expected to be the same as that reported in the original PSD application. In the original PSD application, the coal unloading activities were very conservatively assumed to occur 4 hours per day on every day of the year. Therefore, no additional fugitive dust impacts associated with this proposed action are expected.

Proposed Action:

Increase in Size of the Ash Storage Silo

In order to accommodate changes to the actual operating practices defined in discussions with the railroad and coal supplier, additional storage capacity is required to provide up to nine days of ash storage on site. This will be accomplished by increasing the ash storage silo diameter from 50 feet to 55 feet and the silo height from 120 feet to 185 feet.

Findings:

The increase of the silo building dimensions will not increase ash emissions at any of the transfer points due to the fact that the daily coal consumption by the ICL facility remains unchanged.

In dispersion modeling, fugitive dust emissions are assumed to be released at ambient temperature with virtually no exit velocity. Therefore, fugitive dust concentration estimates are made with the assumption that there is very little momentum or buoyancy plume rise. By increasing the silo height from 120 feet to 185 feet the fugitive dust emission release will be at a greater height, thereby increasing downwind distance and consequently dispersion of the fugitive dust plume prior to its impact with the ground. Therefore, the fugitive dust concentrations at ground-level receptors, under the same ambient conditions, will be less with an increased release height.

In summary, fugitive dust concentrations around the ICL facility will be slightly less if the release height from the ash storage silo is increased from 120 feet to 185 feet. Therefore, the proposed action will not pose any adverse effects to air quality.

TABLE 1. ICL STACK SOURCES AT MAXIMUM IMPACT LOCATIONS
(AUXILIARY BOILERS AT 100 % LOAD)

Pollutant	Averaging Period	Aux. Boilers	New Total	Original Total
SO_2	3-Hour	17.2 (0.30,050)	23.2 (2.20,310)	24.7 (0.25,100)
	24-Hour	7.5 (0.25,330)	7.5 (0.25,330)	11.6 (0.25,110)
	Annual	0.94 (0.25,340)	0.94 (0.25,340)	1.15 (0.25,100)

(AUXILIARY BOILER AT 50 % LOAD)

Pollutant	Averaging Period	Aux. Boiler	New Total	Original Total
SO_2	3-Hour	6.1 (0.30,030)	22.7 (2.2,310)	24.7 (0.25,100)
	24-Hour	3.9 (0.25,350)	6.0 (3.2,310)	11.6 (0.25,110)
	Annual	0.62 (0.25,340)	0.64 (3.0,310)	1.15 (0.25,100)

Note: Concentrations are in $\mu g/m^3$.
Distance and direction shown are in km and degree, respectively, relative to the ICL main stack in parenthesis.
Total = Main Boiler + Auxiliary Boiler(s)

Appendix C

Memorandum from Steve Jelinek, ENSR

re: BACT Analysis

ENSR
ENSR Consulting and Engineering

MEMORANDUM

TO:	Jean Hopkins/US Generating Co.	**DATE:**	April 17, 1992
FROM:	Steve Jelinek	**FILE:**	5402-008-600
RE:	Indiantown Aux Boiler Design Change - Effect on BACT Conclusions	**CC:**	

Per your request, I have evaluated how changing the auxiliary boiler from a single 100% unit to a set of two 50% capacity units would affect the Indiantown PSD Best Available Control Technology (BACT) Analysis. As we discussed, it's my opinion that given certain design considerations, the BACT conclusions would remain the same if this change were made. This memo discusses these conclusions and the design parameters which must be considered in making the change.

I understand that the auxiliary boiler, originally designed to fire either natural gas, propane, or distillate fuel oil at an output of approximately 358 MMBtu/hr with a total maximum operating schedule of 5,000 hours/yr and a maximum of 1,000 hours/yr on oil, is being redesigned. The new configuration, requested by Caulkins Citrus Processing, will consist of two separate combustion units, each sized for a maximum heat rate of approximately 179 MMBtu/hr and the same operating schedule as proposed in the original application. Both units will exhaust through a common stack.

NO_x Control

The BACT for the original design evaluated the technical and economic feasibility of selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), flue gas recirculation (FGR), and low NO_x burners. These alternative controls are all technically feasible for boilers in either size range (360 or 180 MMBtu/hr). However, SCR, SNCR and FGR were all rejected as BACT for economic reasons, while low NO_x burners with a NO_x emission rate of 0.2 lb/MMBtu was concluded to represent BACT. The DER concurred with this conclusion.

The redesign calls for both boilers, which generally will operate at the same time, to exhaust through a common stack. In this configuration, a common SCR system would be technically feasible and would have essentially identical economic impacts as in the previous design since an equivalent amount of catalyst would be required in either case. However, separate emission

TOTAL P.02

control equipment for each boiler would be required for the SNCR, FGR and low NO_x burner alternatives. This would result in slightly higher capital costs for these alternatives for the new design when compared to the costs for the original design. The controlled emissions, however, would remain the same, and thus the economic impact of each alternative would increase. Since the economic impacts for all of these alternatives were concluded to be unreasonable with the original design, the change to two boilers would not alter this conclusion.

Low NO_x burners with a maximum emission rate of 0.2 lb/MMBtu thus would likely still be concluded to represent BACT for the reconfigured auxiliary boiler equipment.

SO_2 and Acid Gas Control

The BACT for the original auxiliary boiler configuration evaluated flue gas desulfurization and fuel sulfur limitations and concluded that limiting the maximum fuel sulfur content to 0.05% was representative of BACT based on unreasonable economic impacts for flue gas desulfurization (FGD). The DER concurred with this conclusion.

As with SCR for NO_x control, the use of two 50% boilers with a common stack would allow the use of a common FGD system. Thus an FGD system for this configuration would have similar capital costs to one designed for a single 100% boiler since the exhaust flows for the two systems would be approximately equal. The emission rates of SO_2 and acid gases would be virtually the same in either case, consequently the cost effectiveness would remain the same and the BACT conclusions would not change. BACT could still be concluded to be represented by low sulfur fuel with a maximum emission rate of 0.052 lb/MMBtu.

CO and VOC Control

The original BACT concluded that combustion controls represented BACT for control of VOC and CO from the auxiliary boiler since the alternative which is generally considered the most stringent, catalytic oxidation, was concluded to be infeasible for an oil-fired source. Oil firing would still be conducted with the new design at the same operating schedule as the original design, thus the technical infeasibility of catalytic oxidation remains unchanged. Were oil firing to be eliminated as an alternative fuel, then the technical arguments against catalytic oxidation would no longer be valid, and the BACT conclusions might change.

However, at this time there is no plan to eliminate fuel oil firing and thus the BACT conclusion of combustion controls for control of CO and VOC remains valid.

Particulate Matter Control

BACT for PM in the original BACT was concluded to be represented by the use of high quality, low ash fuels since fabric filters are infeasible on oil-fired sources and electrostatic precipitators were concluded to be cost ineffective. As discussed, the use of two 50% units firing simultaneously and exiting from a common stack results in a comparable exhaust rate than a single 100% unit. An ESP designed for either configuration would be approximately identical in size and cost, and control the same amount of particulate matter. As a result, the cost effectiveness of this alternative would be identical, and unrepresentative of BACT, for either configuration.

Since neither the fuel mix nor the exhaust rate is changing, the BACT conclusion of 0.02 lb/MMBtu achieved firing low ash fuels, would be concluded to represent BACT for the modified configuration.

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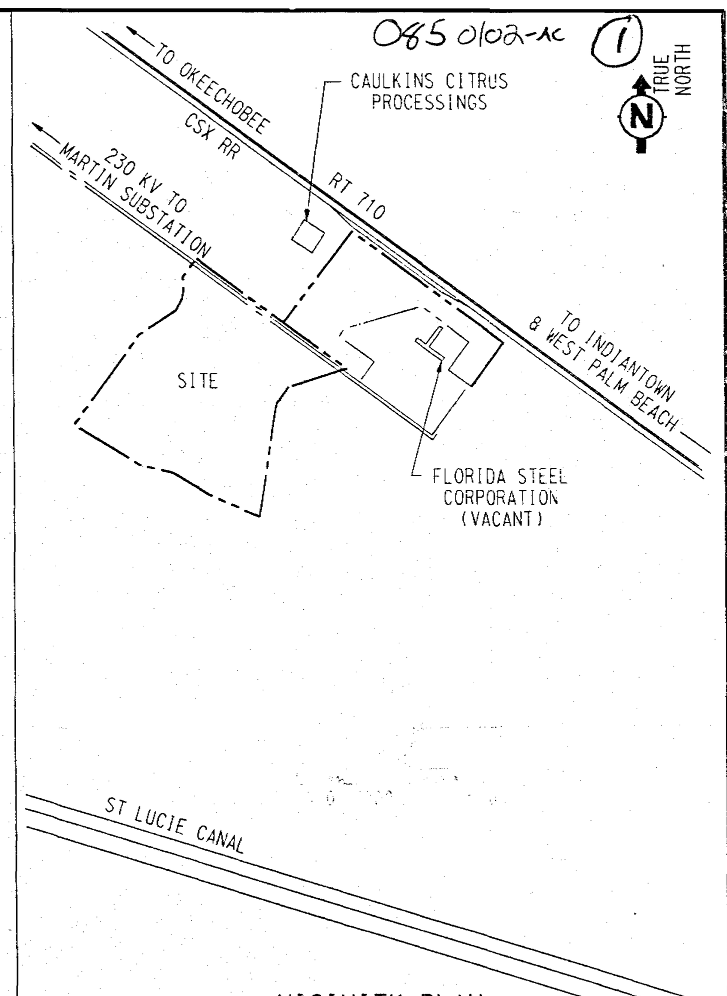

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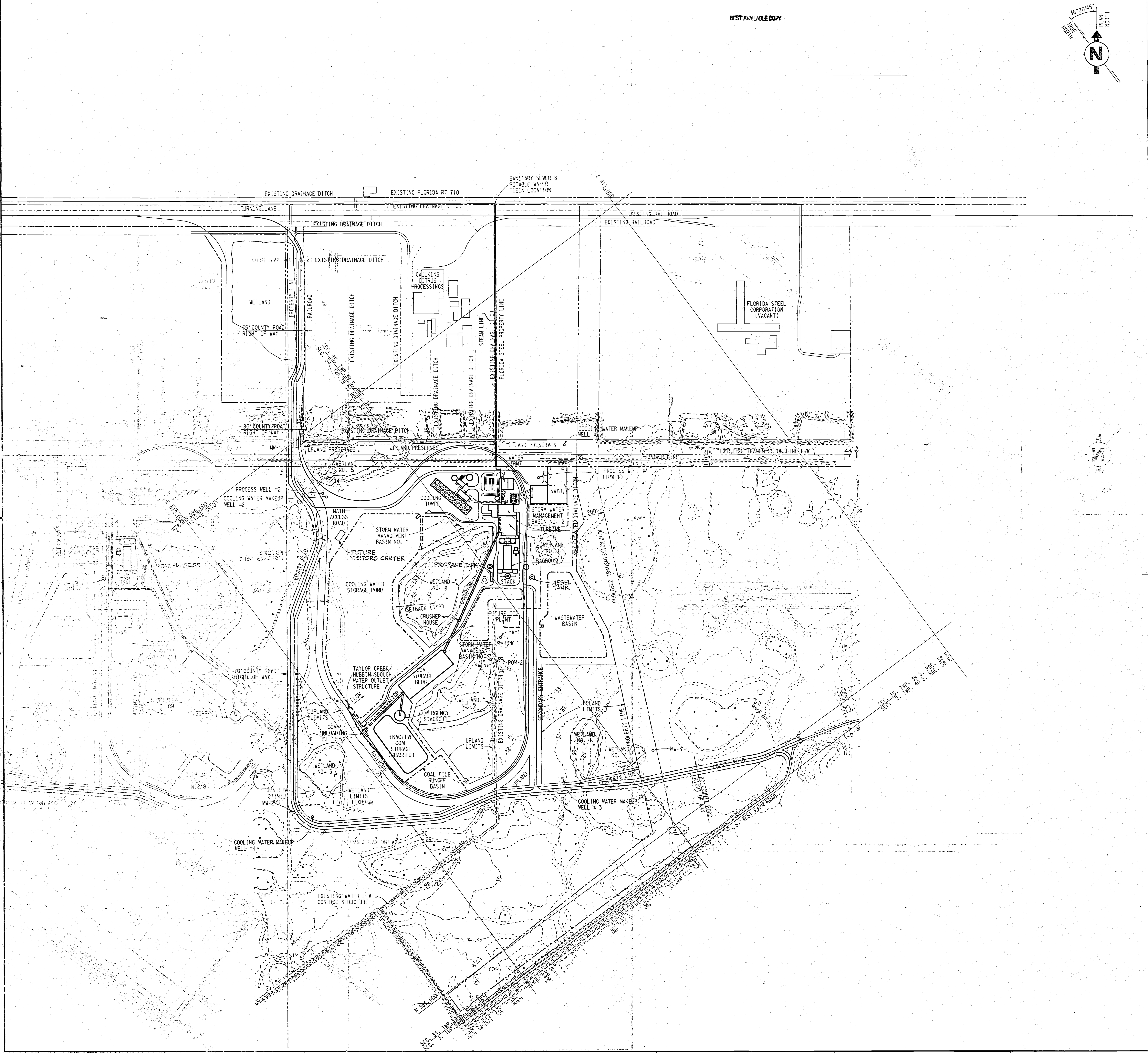

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G	1/8/92	ISSUED FOR INFORMATION	SK	RW			CHC	
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E	6/11/91	REVISED ACCESS ROAD ALIGNMENT	SK	RW			CHC	
D	4/05/91	ISSUED FOR SUFFICIENCY RESPONSE	RWW	RW	JV	WR	CHC	
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B	/ /	REVISED FOR PUD PERMIT						
A	/ /	ISSUED FOR INFORMATION						

SCALE 1"=300' DATE 9-11-90 DESIGNED DRAWN RW CHIEF ENGR.

BECHTEL
GAITHERSBURG, MARYLAND

INDIANTOWN COGENERATION PROJECT
INDIANTOWN FLORIDA

SITE PLAN

JOB NO.	DRAWING NO.	REV.
20524-001	COA 0001A	I

34X44 "E" SIZE

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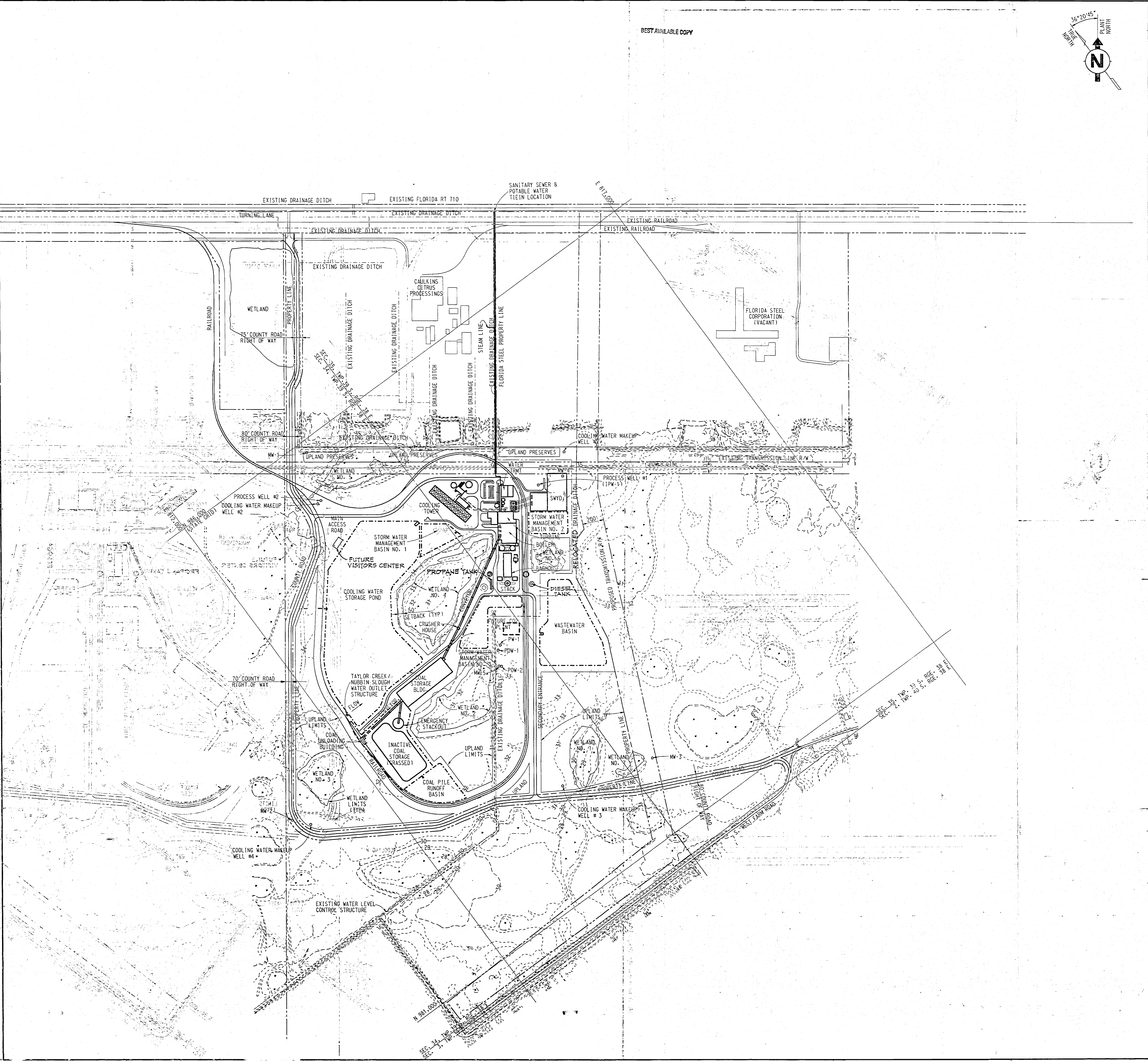

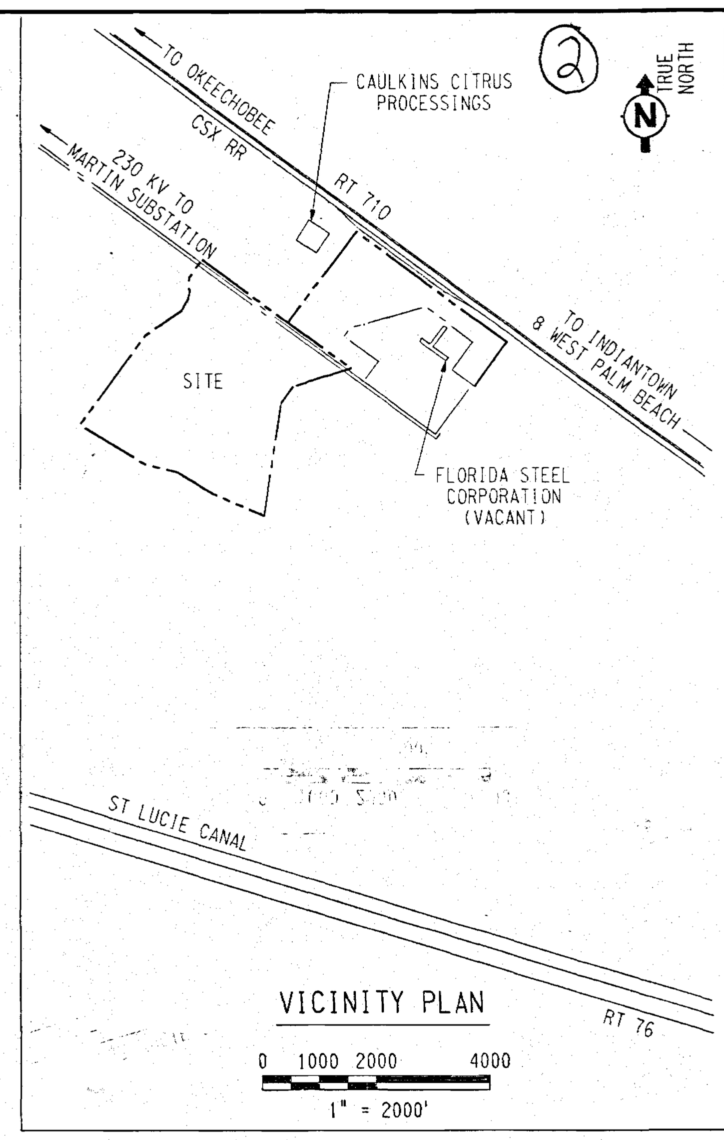

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A	/ /	ISSUED FOR INFORMATION						

SCALE 1"=300' DATE 9-11-90 DESIGNED DRAWN RW CHIEF ENGR.

BECHTEL
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INDIANTOWN COGENERATION PROJECT
INDIANTOWN FLORIDA

SITE PLAN

JOB NO.	DRAWING NO.	REV.
20524-001	COA 0001B	I

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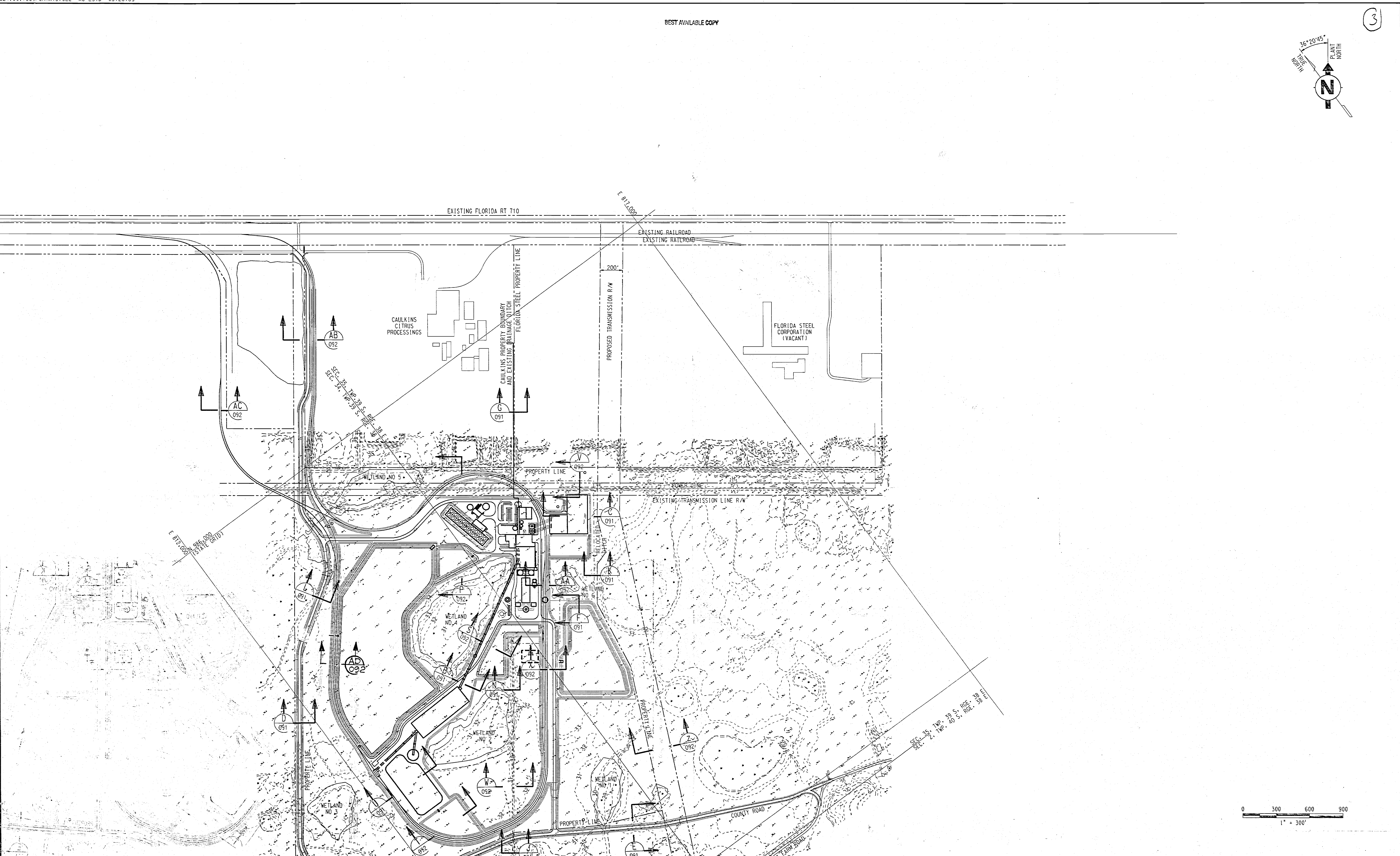

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INDIANTOWN COGENERATION PROJECT
INDIANTOWN FLORIDA

CROSS SECTION LOCATION
SHEET 1 OF 3

JOB NO.	DRAWING NO.	REV.
20524-001	COA 0003	C

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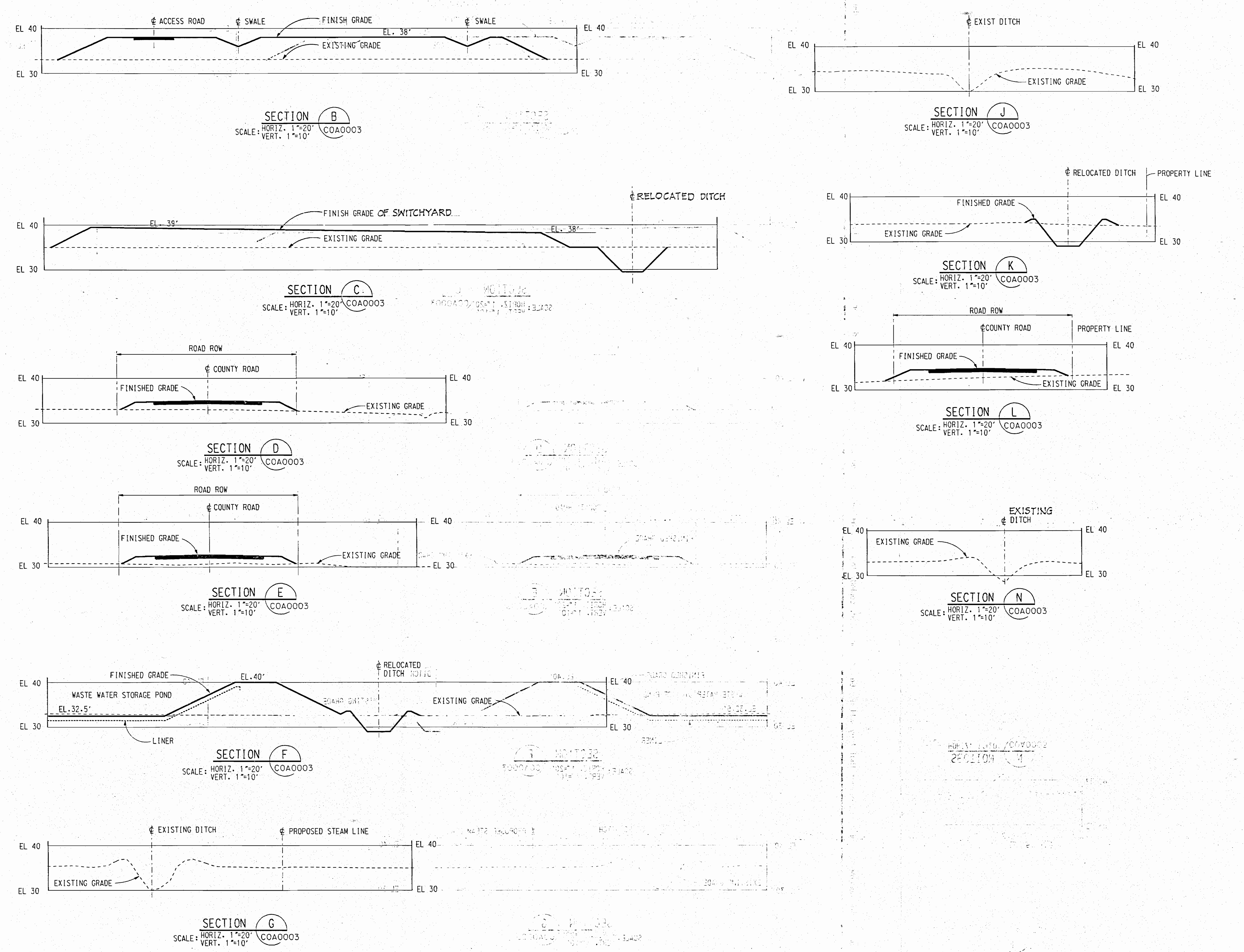

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SCALE: AS NOTED

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INDIANTOWN COGENERATION PROJECT
INDIANTOWN FLORIDA

CROSS SECTIONS
SHEET 2 OF 3

JOB NO.	DRAWING NO.	REV.
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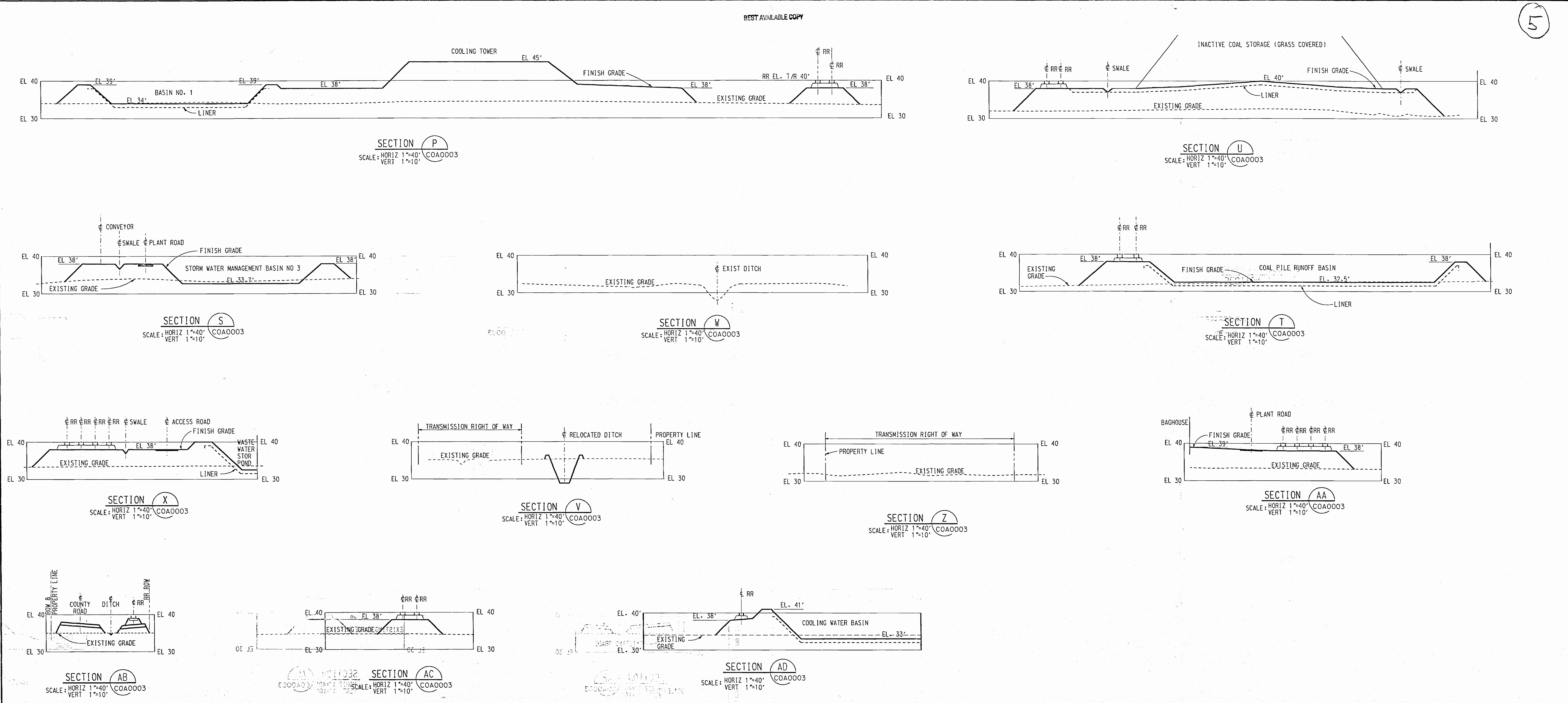

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NO.	DATE	REVISIONS	BY	CHK	DES SUPV.	ENGR.	PROJ ENGR	APPR

SCALE AS NOTED | DATE | DESIGNED | DRAWN | CHIEF ENGR.

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INDIANTOWN COGENERATION PROJECT
INDIANTOWN FLORIDA

CROSS SECTIONS
SHEET 3 OF 3

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