# Curtis H. Stanton Energy Center
# Combined Cycle Unit A



# Sufficiency Report

Manual Number CHSEC- 008

Issued To C. Fancy

Location CDC Mail

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Black & Veatch Corporation

OUC/KUA/FMPA/Southern Co.
Stanton A Project

B&V Project 98362
B&V File 32.0500
April 20, 2001

Mr. Hamilton S. Oven
Administrator, Siting Coordination Office
Department of Environmental Protection
2800 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Stanton Unit A Combined Cycle Project
Supplemental Site Certification Application
FDEP File No. PA 81-14SA2
DOAH Case No. 01-0416EPP
OGC Case No. 01-0176
Response to Statement of Sufficiency

Dear Mr. Oven:

On behalf of the Orlando Utilities Commission, the Kissimmee Utility Authority, the Florida Municipal Power Agency, and the Southern Company-Florida, LLC, and as required by Chapter 403.5067(1)(a) of the Florida Statutes, Black & Veatch submits seven (7) copies of the response to the Statement of Sufficiency received from the Department on March 13, 2001. The seven copies correspond to your assigned Controlled Document copies 1-5 and 40-41 of the Supplemental Site Certification Application.

We appreciate the Department's cooperation and efforts during the review of the application. If you have any questions concerning the project or this submittal, please do not hesitate to call me at (913) 458-7563 or Fred Haddad of OUC at (407) 236-9698.

Very truly yours,

BLACK & VEATCH CORPORATION

Michael Soltys

J. Michael Soltys
Site Certification Coordinator

Enclosures

cc: Certificate of Service List

## CERTIFICATE OF SERVICE

I Certify that a true and correct copy of the Response to Statement of Sufficiency was mailed to the following on this 20TH day of April 2001:

| | |
|---|---|
| Mike McGovern, SJRWMD | Tom Ballinger, PSC |
| | |
| Brad Hartman, FFWCC | Debra Swim, LEAF |
| | |
| Greg Golgowski, ECFRPC | Clair Fancy, FDEP (4) |
| | |
| Ajit Lalchandani, Orange County | Paul Darst, DCA |
| | |
| James Hollingshead, SJRWMD (3) | George Percy, DHR |
| | |
| Sandra Whitmire, FDOT | Pepe Menedez, DOH |
| | |
| Vivian Garfein, FDEP-Orlando (4) | Anthony Cotter, Orange County |
| | |
| Jim Golden, SFWMD | Teresa Remudo-Fries, Orange County |
| | |
| Marc Ady, SFWMD | Charles Lee, Audubon Society |
| | |
| Dorothy Field, Orlando Public Library | |

Michael Soltys

J. Michael Soltys

**Department of Environmental Protection**

**AIR**

1. *The emission limits proposed within the application are based upon the premise that for every hour of the year the unit will be operating with either duct burners firing, in power augmentation mode or firing fuel oil. Based upon its extensive history of permitting combustion turbines during the past two years, the Department does not find this to be reasonable for the determination of permit limits. An allotment of hours for each off-normal mode of operation will be assigned, which is consistent with prior BACT determinations.*

   **Response:** The Stanton Combined Cycle Unit A PSD Application requests the ability to operate at a normal combined cycle mode for up to 8,760 hours per year per CT (includes evaporative cooling and duct firing). Alternative modes of operation requested in the application include power augmentation mode at 1,000 hours per year per CT and operation using distillate fuel oil also at 1,000 hours per year per CT. Power augmentation and fuel oil operating scenarios are considered "off-normal" modes of operation.

2. *The application requests emission limits of CO to be set in lb/hr rather than concentration limits. The Department evaluates BACT for CO based upon concentration rather than mass emission rates, and assigns permit limits in the same fashion.*

   **Response:** The Stanton Combined Cycle Unit A PSD Application proposes BACT for CO to be good combustion control to achieve a CO emission limit of 18.1 ppmvd at 15% $O_2$ for normal combined cycle operation (duct burner), 26.3 ppmvd at 15% $O_2$ for power augmentation, and 14.3 ppmvd at 15% $O_2$ for fuel oil operation. The BACT analysis and conclusions are found in Section 3: Best Available Control Technology, Page 3.1, Section 4.9: Conclusions, Page 4-33 and Section 9.0: Conclusions, Page 9-1.

   Emissions limits for CO in ppm are acceptable to the applicants.

3. *Please confirm the Department's interpretation of the following CO emissions at 100 percent CT output:*

| *Case Pounds Per Hour* | *Operating Mode* | *ppmvd @ 15%$O_2$* | lbs/hr |
|---|---|---|---|
| *1* | *CT operating at 19 degrees F* | *7.4* | *31.0* |
| *13* | *CT with cooling (EC) and duct burners (DB) at 70 degrees F* | *18.1* | *87.51* |
| *18* | *CT with EC, DB and power augmentation at 95 degrees F* | *27.9* | *142.51* |
| *20* | *CT on oil at 19 degrees F* | *14.7* | *71.0* |

**Response:** The above reference data is correct and is based upon GE emission level guarantees.

4. *Please explain the Oxidation Catalyst economic analysis with regard to emissions reductions. According to the Air Construction application form (page 22) maximum requested annual CO emissions are up to 448.12 TPY (gas firing). Considering that the CO emissions resulting from an oxidation catalyst are 74.7 TPY, an emission reduction of 373.42 TPY should be evaluated rather than 319.7 TPY.*

**Response:** The difference in numbers referenced above is due to a BACT analysis based on emissions at a standardized temperature (70° F), whereas the emissions noted on Page 22 are maximum potential emissions for each worst case operating mode at various temperatures (i.e., 19°, 45°, 60°, 75°, and 95° F). The economic analysis (per ton of reduction) as outlined in the application for the BACT will be the same if based on either temperature scenario as long as the comparison remains consistent between the PTE and BACT. The economic analysis was done at a standardized temperature (70° F) to keep the analysis as simple as possible between the various BACT parameters.

5. *Based upon the requested permit levels of CO and related submittals, the application appears to support the installation of an oxidation catalyst. However, the Department wishes to point out that recent tests from TECO's Polk Power Station 7FA resulted in CO emissions of less than 1 ppmvd (gas) and less than 2 ppmvd (oil) at full load. Although contracting for CO limits between GE and its customers may not have caught up with field experience, actual results should be considered in the setting of BACT.*

**Response:** The BACT analysis for CO was based on base case emissions of 394.4 tons per year per CT. This annual rate assumes CT operation for 6,760 hours at 100% load with duct burner firing and 1,000 hours per year at 100% load with steam augmentation and 1000 hours per year at full load on fuel oil. The negative economic impacts, due to an oxidation catalyst, include increased production costs due to decreased efficiency, increased capital cost for the installation of the oxidation catalyst, and increased operating cost due to periodic replacement of the oxidation catalyst. The capital cost and annualized cost for installing an oxidation catalyst is $1,306,000 and $570,000. For 80 percent removal of 74.7 tons per year CO emission, the removal efficiency is $1,800 per ton removed. Annual operation will be such that CO emissions will stay under 394.4 tons per year. Therefore, installation of an oxidation catalyst is not planned for this project. Based on FDEP's internet site, the results of TECO's Polk Power Station 7FA (SCCT) are achieved by good combustion practices. Although they are able to achieve low CO emissions, there are many variables that may not be the same for the Stanton Unit A Project. The ability to tune a combustion turbine to such low loads depends on such items as: fuel quality, ambient temperature and type of combustion system. Stanton Unit A proposes more fuel oil firing (1,000 hours per year versus 750 hours per year) than the TECO Polk facility and 1,000 hours per year of power augmentation that would require the ability of the CT to consistently reduce CO emissions to approximately 96 percent. Unless GE can 100 percent guarantee they are able to achieve lower CO emissions than in their performance data, the AQCS will have concerns and would advise not setting BACT limits for emissions that the combustion turbine manufacturer will not guarantee. It should also be noted that in speaking to TECO on their performance levels, they stated that they could not guarantee these low emissions over time.

The CO exhaust concentration for the CT at 100% load, ambient temperature with duct burner firing (Case 13) is 18.1 ppmvd corrected to 15% $O_2$, and 27.9 for operations with power augmentation. These concentrations are consistent with recent FDEP CT BACT determinations for CO; e.g., City of Tallahassee Purdom Unit No. 8 (BACT CO concentration of 25 ppmvd), Lakeland Electric and Water Utilities Unit No. 5 (BACT CO concentration of 25 ppmvd) and Gulf Power Smith 3 (BACT CO concentration of 16 ppmvd for duct burner and 23 ppmvd for power augmentation). Furthermore, Table 1 and 2 list CCCT and SCCT facilities located in Florida, respectively, that have been recently permitted without the installation of an oxidation catalyst. The CCCT and SCCT units shown in Tables 1 and 2 use either dry low $NO_x$ (DLN) or good combustion practice (GCP) or a combination of both to control CO emissions during natural gas (NG) and fuel oil (FO) firing.

**Table 1**
**Summary of Recent CCCT Units Permitted Without an Oxidation Catalyst**

| State | Permit Date | Facility | # of CTs | Turbine Model | Fuel | Hours | CO Limit | Control Method |
|---|---|---|---|---|---|---|---|---|
| NH | Apr-99 | Newington Energy (525 MW total) | 2 | GE 7FA | NG; FO | 8,760; 720 FO | 15 ppm | GCP |
| NH | Apr-99 | AES Londonderry LLC (720 MW total) | 2 | SW 501G | NG; FO | 8,760; 720 FO | 15 ppm | GCP |
| AL | Dec-97 | Alabama Power – Olin Cogeneration | 1 | GE 7EA (80 MW) | NG | 8,760 | 0.07 lb/MMBtu | GCP |
| AL | May-98 | Alabama Power – GE Plastics Cogeneration | 1 | GE 7EA (80 MW) | NG | 8,760 | 0.08 lb/MMBtu (combined) | GCP |
| AL | Aug-98 | Alabama Power, Plant Barry | 3 | GE 7FA (170 MW) | NG | 8,760 | 0.057 lb/MMBtu | GCP |
| AL | Aug-98 | Alabama Power, Plant Barry | 1 | GE 7FA (170 MW) | NG | 8,760 | 0.060 lb/MMBtu | GCP |
| AL | Jan-99 | Mobile Energy, LLC – Hog Bayou | 1 | GE 7FA (168 MW) | NG; FO | 8,760; 675 FO | 0.040 lb/MMBtu NG; 0.058 lb/MMBtu FO | GCP |
| AL | Mar-99 | Alabama Power – Theodore Cogeneration Facility | 1 | GE 7FA (170 MW) | NG | 8,760 | 0.086 lb/MMBtu | GCP |
| AL | Nov-99 | Tenaska Alabama Partners | 3 | GE 7FA (170 MW) | NG; FO | 8,760; 720 FO | 32.9 ppm NG; 46.7 ppm NG/FO | GCP |
| AL | Apr-00 | Georgia Power – Goat Rock | 8 | GE 7FA (170 MW) | NG | 8,760 | 0.086 lb/MMBtu | GCP |
| FL | Jul-00 | City of Lakeland, McIntosh Power Plant (SC, later CC) | 1 | SW 501G (230 MW) | NG; FO | 7,008; 250 FO | 25 ppm NG; 90 ppm FO | GCP |
| FL | Dec-98 | Santa Rosa Energy Center, Sterling Fibers Mfg. Facility | 1 | GE 7FA (167 MW) | NG | 8,760 | 9 ppm; 24 ppm w/ DB | GCP |
| FL | Nov-99 | Kissimmee Utility Authority, Cane Island Power Park –Unit 3 | 1 | GE 7FA (167 MW) | NG; FO | 8,760; 720 FO | 12 ppm, 20 ppm w/ DB NG; 30 ppm FO | GCP |
| FL | Nov-99 | Lake Worth Generation | 1 | GE 7FA (170 MW) | NG; FO | 8,760; 1,000 FO | 12 ppm NG; 20 ppm FO | GCP |
| FL | Sep-99 | Florida Power & Light – Sanford | 8 | GE 7FA (170 MW) | NG, FO | 8,760; 500 FO | 12 ppm NG; 20 ppm FO | GCP |
| FL | Feb-00 | Gainesville Regional Utilities, Kelly Generating Station | 1 | GE 7EA (83 MW) | NG; FO | 8,760; 1,000 FO | 20 ppm NG; 20 ppm FO | GCP |

**Table 1 (Continued)**
**Summary of Recent CCCT Units Permitted Without an Oxidation Catalyst**

| State | Permit Date | Facility | # of CTs | Turbine Model | Fuel | Hours | CO Limit | Control Method |
|---|---|---|---|---|---|---|---|---|
| FL | Sep-98 | FPL Fort Myers | 6 | GE 7FA (170 MW) | NG | 8,760 | 9 ppm | GCP |
| FL | Draft Permit | Hines Energy (FPC) | 2 | SW 501F (165 MW) | NG; FO | 8,760; 1,000 FO | 25 ppm NG - full load; 30 ppm FO | GCP |
| MS | Nov-97 | LS Power Limited Partnership | 3 | SW 501G (281 MW) | NG; FO | 8,760 (up to 10% FO) | 30.3 ppm NG; 36 ppm FO | GCP |
| MS | Dec-98 | Mississippi Power Corp., Plant Daniel | 4 | GE 7FA (170 MW) | NG | 8,760 | 0.057 lb/MMBtu | GCP |
| MS | Apr-00 | Duke Energy Attala, L.L.C. | 2 | GE 7FA (170 MW) | NG | 8,760 | 20 ppm | GCP |
| IL | Dec-01 | Peoples Gas, McDonell Energy | 10 | 250 MW | NG, ethane | 8,760 | 0.031 lb/MMBtu | GCP |
| IL | Jun-99 | LS Power, Kendall Energy | 4 | 220 MW | NG | 8,760 | 0.0626 w/DB, 0.0511no DB, >75% load | GCP |
| IL | Jul-99 | Reliant Energy, Cardinal | 3 | 211 MW | NG, RFG | 8,760 | 0.0472 lb/MMBtu | GCP |
| IL | Sep-99 | Mid America, Cordova Energy Center | 2 | 290 MW | NG | 8,760 | 0.0547 lb/MMBtu: loads > 75%, after 9/2001 | GCP |
| IL | Jan-00 | LS Power, Nelson Project | 4 | 220 MW | NG; FO | 8,760 | 0.0626 w/DB, 0.0511no DB; >75% load | GCP |
| IL | Feb-00 | Ameren CIPS | 2 | 600 MW | NG | 8,760 | 0.06 lb/MMBtu | GCP |

**Table 2**
**Summary of Recent SCCT Units Permitted without an Oxidation Catalyst**

| State | Permit Date | Facility | Turbine Model | Fuel | Hours | CO Limit | Control Method |
|---|---|---|---|---|---|---|---|
| FL | Oct-99 | Polk Power (TECO) | GE 7 FA (165 MW) x2 | NG; FO | 5,130; 750 FO | 15 ppm NG; 33 ppm FO | GCP |
| FL | Nov-99 | Oleander Power | GE 7FA (190 MW) x5 | NG; FO | 3,390; 1,000 FO | 12 ppm NG; 20 ppm FO | GCP |
| FL | Dec-99 | Reliant Energy Osceola | GE 7FA (170 MW) x3 | NG; FO | 3,000; 2,000 FO | 10.5 ppm NG; 20 ppm FO | GCP |
| FL | Oct-99 | Jacksonville Electric Authority – Brandy Branch | GE 7FA (170 MW) x3 | NG; FO | 4,000; 800 FO | 15 ppm NG; 20 ppm FO | GCP |
| FL | Dec-99 | IPS Avon Park Corp. - Vandola Power Project | GE 7FA (170 MW) x4 | NG; FO | 3,390; 1,000 FO | 12 ppm NG; 20 ppm FO | GCP |
| FL | Jan-00 | IPS Avon Park – Shady Hills | GE 7FA (170 MW) x3 | NG; FO | 3,390; 1,000 FO | 12 ppm NG; 20 ppm FO | GCP |
| FL | Jun-00 | Palmetto Power | SW 501F (180 MW) x3 | NG | 3,750 | 25 ppm (15 ppm after 1st yr.) | GCP |
| GA | Dec-98 | Tenaska Georgia Partners, L.P. | GE 7FA (160 MW) x6 | NG; FO | 3,066; 720 FO | 15 ppm NG; 20 ppm FO | GCP |
| GA | Jun-99 | West Georgia Generating; Thomaston | GE 7FA (170 MW) x4 | NG; FO | 4,760; 1,687 FO | 15 ppm NG; 20 ppm FO | GCP |
| GA | Oct-99 | Heard County Power | SW 501FD (170 MW) x3 | NG | 4,000 | 25 ppm | GCP |
| GA | Aug-99 | Georgia Power, Jackson County | GE 7EA (76 MW) x16 | NG; FO | 4,000; 1,000 FO | 0.101 lb/MMBtu NG; 0.046 lb/MMBtu FO | GCP |
| NC | Nov-99 | Carolina Power & Light, Richmond Co. | GE 7FA (170 MW) x7 | NG; FO | 2,000; 1,000 FO | 15 ppm NG; 20 ppm FO | GCP |
| NC | Nov-99 | Carolina Power & Light, Rowan Co. | GE 7FA (170 MW) x5 | NG; FO | 2,000; 1,000 FO | 15 ppm NG; 20 ppm FO | GCP |
| NC | Jun-99 | Rockingham Power (Dynegy) | SW 501F (156 MW) x5 | NG; FO | 3,000; 1,000 FO | 25 ppm NG; 50 ppm FO | GCP |
| WI | Jan-99 | RockGen Energy | GE 7FA (175 MW) x3 | NG; FO | 3,800 Total 800 FO | 12 ppm NG; 15 ppm FO (load>75%) & 24 ppm FO (load<75%) | DLN, GCP |
| WI | Feb-99 | Southern Energy | GE 7FA (180 MW) x2 | NG; FO | 8,760 Total, 699 FO | 12 ppm NG; 15 ppm FO (load>75%) & 24 ppm FO (load<75%) | DLN, GCP |

In addition, please note that the installation of a CO oxidation catalyst for Stanton Unit A will provide no air quality benefits. Instead, if the project installed an oxidation catalyst it should be noted the installation would have negative energy, environmental, and economic impacts. The oxidation catalyst would increase the back-pressure on the turbine; thereby increasing emissions per unit of electric generation due to decreased turbine efficiency and increased fuel consumption. The major environmental disadvantage that exists when using an oxidation catalyst to reduce CO emissions during all three possible operating cases is that a percentage of the sulfur dioxide ($SO_2$) in the flue gas will oxidize to sulfur trioxide ($SO_3$). The higher the operating temperature, the higher the $SO_2$ to $SO_3$ oxidation potential. It is estimated that approximately 30 to 60 percent of the $SO_2$ in the flue gas can oxidize to $SO_3$ as a result of the CO oxidation catalyst being installed after the combustion turbine outlet with high temperatures. The $SO_3$ will react with the moisture in the flue gas to form sulfuric acid ($H_2SO_4$) mist in the atmosphere. The increase in $H_2SO_4$ emissions would increase $PM_{10}$ (matter less than 10 microns in diameter) emissions. Moreover, the use of an oxidation catalyst and SCR catalyst will increase front and back half particulate emissions during all three operating cases in the form of $H_2SO_4$ and ammonium bisulfate as a result of ammonia usage with the SCR and increased $SO_3$ production. The front half-particulate emissions will increase in the form of ammonium bisulfate assuming all $SO_3$ reacts to form ammonium bisulfate. Under normal conditions, there will be a mixture of front and back half increase in particulate emissions. Additionally, the CO catalyst does not remove or destroy CO but rather simply accelerates the natural atmospheric oxidation of CO to $CO_2$ (possible contributor to global warming). Dispersion modeling of CO emissions, under worst-case operating conditions, indicates that maximum CO air quality impacts, without the use of an oxidation catalyst system, will be insignificant. Ambient CO levels are well within established air quality standards. Because maximum CO air quality impacts without an oxidation catalyst control system are already insignificant, requiring expensive controls to further reduce CO emissions by less than 64 TPY seems to serve no environmental purpose.

6. *The applicant should be advised that ammonia slip is currently being permitted at 5 ppmvd.*

**Response:** From a safety and health standpoint, a monitoring level set a 10 ppmvd appears to be a reasonable level for ammonia slip based on other sites currently operated by Southern Company. Ammonia is not a currently listed regulated pollutant. The applicants are amenable to discussion of this issue during air permit preparation.

7. *Please indicate the maximum gross MW capability of the combined cycle unit, and under what operating conditions this output is achieved. Please provide the same information for the maximum heat input of the CTs and the gas-fired duct burners under ISO conditions. Maximum combined heat input rates have been*

*specified for non-ISO conditions at 2402.0 MMBtu/hr firing natural gas (Case 4 while firing duct burners) and 2067.6MMBtu/hr oil firing (Case 20).*

**Response:** At 23° F (wet bulb at 19° F), the maximum MW capability of each combustion turbine unit is 189 MW and the steam turbine is 319 MW. Thus, the total maximum MW capability of Stanton A is 697 MW (@ 23° F). The heat input for this case is 1,898 MMBtu/hr for each combustion turbine and 533 MMBtu/hr for each duct burner. Total heat input for Stanton A (CT 1 + CT 2 + DB 1+DB 2) for this case is 4,863 MMBtu/hr.

8. *Please provide the estimated time frames required, estimated number of annual startups and the estimated emission levels of $NO_X$, CO and $PM/PM_{10}$ during hot and cold startup periods. The Department intends to define these levels in the setting of BACT.*

**Response:** It is currently impossible to determine an estimated number of annual start-up periods and emissions during startup for the operation of Stanton Unit A. The permittee is, however, comfortable with standard FDEP language outlining start-up limitations, such as "Excess emissions resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized but in no case exceed four hours in any 24-hour period for a cold startup and two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration."

9. *The Department requires as a submittal, a project specific, written cost estimate of a $SCONO_X$ control system, to be supplied by the technology provider (Alstrom Power). In addition to capital cost requirements, the submittal should include vendor estimates for use in determining any applicable annualized operating and maintenance costs.*

**Response:** The applicants have requested a project specific budgetary cost estimate for a SCONOx control system from Alstom Power for the Stanton Unit A CCCT Project via facsimile on March 19, 2001. A response was requested by Monday, March 26, 2001. The budgetary quote that was used in the BACT analysis was provided to Black & Veatch on April 26, 2000.

The FDEP should note that supplying project specific budgetary quotes for BACT analyses can take substantial time, since vendors realize there is no immediate financial return for their efforts. Alstom Power has recently provided a budgetary quote for another GE 7FA CCCT facility via e-mail to Black & Veatch on February 1, 2001 and it is listed below for your reference. The February 1, 2001 budgetary quote was based on firing a GE 7FA with duct burners on natural gas for 8,472 hours per year at 100 percent load and for firing fuel oil in a GE 7FA without duct firing at 100 percent load for 288 hours per year. Since the Stanton

Unit A CCCT Project has more fuel oil firing (712 hours for a total of 1,000 hours per turbine), the capital cost is expected to increase from this most recent cost estimate. Due to the time constraints Black & Veatch has recalculated the SCONOx capital and annualized costs based on this recent budgetary quote. The February 1, 2001 budgetary quote provided by Mr. Rick Oegema, of Alstom Power, had informed Black & Veatch that fuel oil fired cases would be the worst case design scenario for a project and the cost provided for that case would certainly include any necessary reductions during natural gas firing. Tables 4-4 and 4-5 in the BACT have been revised based on the Alstom Power February 1, 2001 budgetary quote and are attached in this document for your reference.

Specifically, the direct and indirect capital costs in Table 4-4 have been revised based on the February 1, 2001 Alstom Power budgetary quote. The total direct cost excluded the catalyst replacement cost for both the SCONOx and SCR/oxidation catalyst system. The estimated catalyst costs are listed in Table 4-4 under the "Remarks" column. It should be noted that the SCONOx replacement cost is based on a 10-year life for the first layer of catalyst. The SCR/oxidation catalyst indirect costs were determined based on percentages listed in the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (Fifth Edition, 1996). The SCONOx indirect costs were adjusted based on reasonable project estimates, because if OAQPS Cost Manuel percentages were applied then the indirect costs would be misrepresented.

The direct and indirect annual costs in Table 4-5 have been revised based on the February 1, 2001 Alstom Power budgetary quote. The SCR and oxidation catalyst replacement cost was calculated based on a 3-year life, 15 percent for installation, and 5 percent for freight. The SCONOx catalyst replacement cost was based on $230,000 per year for catalyst over a 10-year life that corresponds to a capital recovery factor of 0.1424 (7.0 percent real interest rate), 15 percent for installation, and 5 percent for freight. The SCR/oxidation catalyst indirect annual costs were determined based on percentages listed in the OAQPS Control Cost Manuel. The SCONOx indirect annual costs were adjusted based on reasonable project estimates, because if OAQPS Control Cost Manuel percentages were applied then the indirect annual costs would be misrepresented.

ALSTOM POWER E-MAIL

From:gerald.r.oegema@power.alstom.com
Sent: Thursday, February 01, 2001 2:06 PM
To: Holscherga@bv.com
Cc: ronald.r.bevan@power.alstom.com
Subject: B&V Project 099262

Greg, further to your request of January 26, 2001, please note the following.

We have evaluated the performance and emission data for the cases provided, namely the $NO_x$ emission limits of 2.0 ppmvd and 3.5 ppmvd while firing natural gas, and 15 ppmvd while firing fuel oil. The fuel oil firing case is the size controlling case, as the reduction from 42 to 15 ppmvd requires more catalyst than either of the natural gas fired cases. As a result, we are providing cost and performance data for two cases; fuel oil firing and a $NO_x$ reduction from 42 to 15 ppmvd, and natural gas firing and a $NO_x$ reduction from 9 to 2 ppmvd. Both cases provide a CO emission reduction of 90%.

Included in our scope is the $SCONO_x$ reactor including inlet and outlet dampers, all $SCOSO_x$ and $SCONO_x$ catalyst, inlet and outlet transitions to the reactor including expansion joints, regeneration gas production and distribution piping and valves, regeneration gas condensing and condensate collection system, catalyst installation and removal system, PLC control system and instrumentation, freight, as well as all engineering, design, and project management services to support the execution of the project.

Fuel Oil Firing
Budgetary Capital Cost Estimate - $ 19,800,000
Steam consumption for regen gas production - 20,500 #/hr
Natural gas consumption for regen gas production - 340 #/hr
Pressure drop through the $SCONO_x$ system - 5.3 in w.c.
O&M cost estimate, including catalyst washing - $310,000 per year
Catalyst replacement cost estimate - $230,000 per year

Natural Gas Firing
Budgetary Capital Cost Estimate - $ 15,600,000
Steam consumption for regen gas production - 19,700 #/hr
Natural gas consumption for regen gas production - 330 #/hr
Pressure drop through the $SCONO_x$ system - 3.8 in w.c.
O&M cost estimate, including catalyst washing - $310,000 per year
Catalyst replacement cost estimate - $230,000 per year

Costs provided are for one $SCONO_x$ system for each CCGT.

I trust that this meets with your immediate needs. Please contact me if you have
any questions.

Regards,

Rick Oegema

| BACT Table 4-4 (REVISED)<br>Combined $NO_x$ and CO Control Alternative Capital Cost Per GE 7FA CTG/HRSG Unit. | | | | |
|---|---|---|---|---|
| | **$SCONO_x$ System** | **SCR/ Oxidation Catalyst** | **LNB** | **Remarks** |
| **Direct Capital Cost** | | | | Cost based on emissions in Tables 4-1, 4-2, and 4-3 in BACT |
| SCR & Oxidation Catalyst System | N/A | 1,907,000 | N/A | Estimated from Engelhard Corporation. |
| $SCONO_x$ System (Includes catalyst) | 19,800,000 | N/A | N/A | Estimated from Alstom Power. |
| Catalyst Reactor Housing | Included | 268,000 | N/A | Estimated by Alstom Power & scaled from an estimate by Engelhard Corporation. |
| Control/Instrumentation | Included | 180,000 | N/A | Estimated; includes controls and monitoring equipment. |
| Ammonia (Storage & Handling)) | N/A | 200,000 | N/A | Estimated from previous projects. |
| **Purchased Equipment Costs** | 19,800,000 | 2,555,000 | N/A | |
| Sales Tax | N/A | N/A | N/A | No sales tax on generating equipment for this project. |
| Freight | Included | 128,000 | N/A | 5% of Purchased Equipment Costs |
| **Total Purchased Equipment Costs (PEC)** | 19,800,000 | 2,683,000 | N/A | |
| **Direct Installation Costs** | | | | |
| Balance of Plant | Included | 805,000 | N/A | For SCR: 8% Foundation & Supports, 14% Handling & Erection, 4% Electrical Installation, 2% Piping, 1% Insulation and 1% Painting. $SCONO_x$ bid included installation. |
| **Total Direct Cost Less Catalyst** | **19,570,000** | **1,998,000** | Base | Catalyst cost is excluded as annual O&M cost. SCR and oxidation catalyst costs are $826,000 and $664,000, respectively. SCONOx replacement cost estimate is $230,000 per year, based on a 10-year life. |
| **Indirect Capital Costs** | | | | |
| Contingency | 594,000 | 537,000 | N/A | For SCR: 20% of Total PEC; For $SCONO_x$: 3% of Total PEC |
| Engineering and Supervision | Included | 268,000 | N/A | For SCR: 10% of Total PEC |
| Construction & Field Expense | 198,000 | 134,000 | N/A | For SCR: 5% of Total PEC; For $SCONO_x$ 2.5% of Total PEC |
| Construction Fee | 396,000 | 268,000 | N/A | For SCR: 10% of Total PEC; For $SCONO_x$ 5% of Total PEC |
| Start-up Assistance | Included | 54,000 | N/A | For SCR: 2% of Total PEC |
| Performance Test | 40,000 | 27,000 | N/A | For SCR: 1% of Total PEC; For $SCONO_x$ 0.5% of Total PEC |
| **Total Indirect Capital Costs** | 1,228,000 | 1,288,000 | Base | |
| **Total Installed Cost (TIC)** | **20,798,000** | **3,286,000** | Base | |

| BACT Table 4-5 (REVISED)<br>Combined $NO_x$ and CO Control Annualized Cost Per GE 7FA CTG/HRSG Unit | | | | |
|---|---|---|---|---|
| | **$SCONO_x$ System** | **SCR/Oxidation Catalyst** | **LNB** | **Remarks** |
| **Direct Annual Cost** | | | | Cost based on emissions in Tables 4-1, 4-2, and 4-3 in BACT |
| Catalyst Replacement | 40,000 | 686,000 | N/A | Catalyst life of 3 year for SCR/Oxidation catalyst and 10 year life for $SCONO_x$ catalyst. |
| Operation and Maintenance | 310,000 | 40,000 | N/A | Estimated from Alstom Power & includes catalyst washing and materials. For SCR/Oxidation catalyst assumed 2 hr/day, 8,760 hr/yr at $40/hr and includes materials. |
| Reagent Feed | N/A | 87,000 | N/A | Assumes 1.4 stoichiometric ratio. |
| Natural Gas Consumption | 218,000 | N/A | N/A | Based on 340-lb/hr natural gas consumption. |
| Power Consumption | 4,000 | 7,000 | N/A | Includes injection blower and vaporization of ammonia for SCR and damper actuation for $SCONO_x$. |
| Lost Power Generation | | | | |
| $SCONO_x$ Washing | 175,000 | N/A | N/A | Down time due to $SCONO_x$ washing period. |
| Steam Consumption | 694,000 | N/A | N/A | Loss based on 20,500 lb/hr of steam required. |
| Backpressure | 895,000 | 95,000 | N/A | Includes back-pressure on the combustion turbine. |
| Annual Distribution Check | N/A | 8,000 | N/A | Required for SCR, estimated as 0.5% of total direct cost less the catalyst cost. |
| **Total Direct Annual Cost** | 2,336,000 | 923,000 | N/A | |
| **Indirect Annual Costs** | | | | |
| Overhead | 31,000 | 20,000 | N/A | For SCR 60% of O&M Labor; For $SCONO_x$: 10% of O&M Labor |
| Administrative Charges | 63,000 | 66,000 | N/A | For SCR 2% of Total Installed Cost; For $SCONO_x$: 0.3% of TIC |
| Property Taxes | 104,000 | 90,000 | N/A | For SCR 2.75% of Total Installed Cost; For $SCONO_x$: 0.5% of TIC |
| Insurance | 42,000 | 33,000 | N/A | For SCR 1% of Total Installed Cost; For $SCONO_x$: 0.2% of TIC |
| Capital Recovery | 2,284,000 | 361,000 | N/A | Capital Recovery Factor times the Total Installed Cost |
| **Total Indirect Annual Costs** | 2,524,000 | 570,000 | N/A | |
| **Total Annualized Cost** | **4,860,000** | **1,493,000** | N/A | |
| Annual Emissions, tpy | 144.1 | 220.1 | 918.5 | Emissions taken from Tables 4-1, 4-2 and 4-3 in BACT |
| Emissions Reduction, tpy | 774.3 | 698.3 | N/A | Emissions calculated from Tables 4-1, 4-2, 4-3 in BACT |
| **Total Cost Effectiveness, $/ton** | **6,300** | **2,100** | N/A | Total Annualized Cost / Emissions Reduction |
| **Incremental Annualized Cost** | **3,367,000** | N/A | N/A | Total annualized SCR/Oxidation catalyst system cost minus the total annualized SCONOx system cost |
| **Incremental Reduction** | **44,000** | N/A | N/A | Total Incremental Annualized Cost / Incremental Emissions Reduction |

10. *Each economic analyses should be revised to incorporate the information specified above as well as the utilization of OAQPS Control Cost Method factors (e.g., contingency). Additionally, according to the application's Section 4.6.7.2, lost revenues are included in the annualized cost estimate. These should be excluded from the analyses.*

***Response:*** The 3 percent contingency value as a function of the total purchased equipment cost suggested in the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (Fifth Edition, 1996) is judged to be inaccurate for SCR and oxidation catalyst systems as compared to actual values typically used in the construction field for this level of estimating. There are many potential items and uncertainties that are not captured by the cost items included in the estimate including ammonia permitting cost, ammonia suppression, changes between cost quotes and contract values, changes in operating conditions, process contingency, etc. For example, the original capital cost estimate for the Kissimmee Unit 3 plant was estimated to be $117.6 million and the current estimate to complete is $135.7 million, a 15.4 percent increase. The increase was due to increased equipment cost, scope changes, labor/wage increases, and schedule acceleration.

The OAQPS Control Cost Manuel (Fifth Edition) states in regards to the intended users of the manual, "Moreover, the user should be able to exercise "engineering judgment" on those occasions when the procedures may need to be modified or disregarded." This was the case for the SCR/Oxidation catalyst system, but not for the SCONOx system. The 3 percent contingency factor for the $SCONO_x$ system is estimated to be appropriate based on the total purchased equipment cost. Alstom Power believes the project contingency should be about the same for a SCONOx system compared to a SCR/Oxidation catalyst system. Therefore, the contingency factor was estimated for both post combustion control systems to appropriate percentages for the project based on "engineering judgment."

In addition, the Electric Power Research Institute published the document titled, $NO_x$ Emissions: Best Available Control Technology, A Gas Turbine Permitting Guidebook in November 1991 and list under $NO_x$ control cost (Page 5-5) the following text:

> "Based on experience with other cost methodology sources, the contingency factor recommended by the OAQPS Manual (3% of the total equipment cost) is a lower-bound estimate. Standard EPA guidance for pollution control costing is a contingency factor of 10 to 50% of the sum of direct and indirect costs. (10) A contingency factor of 20% of the sum of direct and indirect costs was used in the economic analyses conducted by the EPA in support of the NSPS for industrial and small boilers and municipal waste combustors. (11, 12) Based on this range of values, it is recommended that individual utilities use the contingency factor that would normally be used in-house in procurement or rate estimation procedures, and document the validity of the factor for the case in

question. The factor recommended by OAQPS should be used as a default value when more appropriate information is not available."

Furthermore, the project economic criteria used in this BACT economic analyses uses a contingency value of 20 percent as listed in the previous capital cost estimate example shown in the EPA BACT guidance document (March 15, 1990) on the use of the "top-down" approach to BACT determinations. The EPA document was published by the OAQPS, Air Quality Management Division Noncriteria Pollutants Program Source Review Section, March 15, 1990, and is titled, "Top Down" Best Available Control Technology Guidance Document. The example in Appendix B, Page B-5 shows a contingency of 20 percent.

The lost power generation is a function of the lost capacity from the combustion turbine, operating hours and the lost power generation revenue. The lost power generation revenue should be included since the owner will incur a loss of revenue that will not be recoverable. The back-pressure on the combustion turbine will decrease the total power output that the owner could have sold to generate revenue. The owner will also incur a loss in revenue from the SCONO$_x$ system by consumption of steam and natural gas for the regeneration process that could have been used to operate a steam turbine and a combustion turbine. The owner will also incur a loss in revenue when the unit is offline for annual washing of the SCONO$_x$ catalyst.

Additionally, the lost revenue calculation in the economic analysis is very minor and is included in both baselines in the SCONO$_x$ and SCR/Oxidation Catalyst comparison. Removal of these costs will have only a net $37,000 impact on a total incremental annualized cost of $6,600,000. However, the economic analysis for the SCONOx system has been updated with the most recent SCONO$_x$ budgetary quote that Black & Veatch has received from Alstom Power (see Tables 4-4 and 4-5). In addition, the annualized cost for the SCR/Oxidation Catalyst system has been recalculated. The total indirect annual cost has been recalculated for the SCR and oxidation catalyst alternative. The capital recovery cost in the original BACT was calculated by subtracting the SCR/Oxidation catalyst system cost from the total installed cost and then multiplied by the capital recovery factor. This has been recalculated to only multiply the capital recovery factor by the total installed cost of the SCR/Oxidation catalyst. The total annualized cost and cost effectiveness were then recalculated based on the revised indirect annual cost. Table 4-5 has been updated with these changes and the total annualized cost recalculated to be $1,493,000. This revised annualized cost per CTG/HRSG unit results in a cost effectiveness of approximately $2,100 per ton of NO$_x$ and CO removed.

## WATER

1. *The applicant has provided a single line diagram for the new expansion. This diagram does not show chemical feeds and all treatment systems. Some existing treatment units will be used for the treatment of the wastewater generated from the new expansion. A revised single line diagram for the entire facility (Units 1, 2, and A) showing all treatments units, chemical feeds, and disposal methods is requested. Please show average daily and maximum daily flows for all existing units and the expansion.*

   *Response:* The Unit 1 and 2 water mass balance shows the water uses and wastewater systems for the existing facilities and infrastructure. This drawing is based on Figure 3.5-1 submitted with the Stanton Energy Center Unit 2 Site Certification Application and shows all interfaces with new facilities. Water mass balance is attached as OUC waste water diagram, Rev. 9 and shows the chemical feeds, treatment systems, and disposal methods for Unit A as well as interconnections with the existing infrastructure. The attached water balances also include the average daily and maximum daily flows for all 3 units.

2. *On Figure 3.5-1 (single line diagram), please show final disposition of the treated water and wastewater for "OUC Tower Blowdown Treatment System" (Node 60).*

   **Response:** The revised water mass balances depict the final disposition of the treated water and wastewater for the cooling tower blowdown treatment system. The distillate from the new Stanton A CTBT system will be recycled to Stanton A's cooling tower under normal operating conditions; it will only be sent to the makeup pond for emergency disposal. The distillate is high quality water and should not affect the use of the makeup pond water or cause any environmental impacts.

3. *Please provide details of the SEC Recycle System. What is the make up of the basin structure?*

   **Response:** The existing recycle system was previously described and licensed under the Units 1 and 2 Site Certifications. A description of the recycle system taken from the Unit 1 Site Certification Application is attached.

4. *Section 3.6 (Page 3-13). Please show the new brine concentrator system on the single line diagram. Also provide details of the boiler cleaning waste neutralization system. Where does the cleaning waste disposed of?*

   **Response:** The new brine concentrator is illustrated on the revised water mass balance for Stanton A, which is attached. There is no boiler cleaning waste neutralization system at the site. The boiler cleaning contractor will remove the cleaning waste from the site and dispose of it by an approved method. The disposal method and location will be specified in the contractor's contract and will meet all federal and state regulations.

5. *3.6.6. Please provide details of the neutralization basin. Show all incidental waste stream and flow volumes from existing and the new units.*

**Response:** The neutralization system was previously licensed under the Unit 1 Site Certification. The attached description of the recycle neutralization basin system is taken from the Unit 1 Site Certification Application. The primary flow to the neutralization basin is regeneration waste from the demineralizer system. This flow is shown on the portion of the water balance representing Units 1 and 2. Acid or caustic will be added to the basin as required to control the pH within an acceptable range. Drains from chemical containment areas will also be routed to the neutralization basin. The flows associated with these drains will generally be low volume and infrequent.

6. *5.2.1. Oil and grease concentration of the water discharged from the transformer enclosure will be at 10.0 mg/L. The discharge concentration is limited at 5.0 mg/L. If the contamination is due to petroleum based oils, the Department will suggest sampling for TRPH (Total Residual Petroleum Hydrocarbons). The limit for the TRPH concentration in the effluent remains at 5.0 mg/L. The Department may require effluent monitoring for this discharged. Please provide details of the disposal area.*

**Response:** The large site transformers will be provided with a walled containment to hold any transformer oil leakage. A drain pipe and valve will be provided in the enclosure. The drain valve will normally be closed. Any rain water that collects within the enclosure will be checked for oil before discharge. Any oil present will be cleaned up before draining water from the enclosure. The contained water will be released as site runoff after oil removal. The transformer oil that will be used is electrical insulating oil, per ASTM D-3487 type 1 inhibited.

7. *Projected Water Use on Page 5-28. It is indicated that the proposed expansion will require up to 2.91 mgd under normal operating condition. OUC should consider using up to 3 mgd available from Orange County Landfill located adjacent to OUC site.*

**Response:** The applicants discussed this item with the FDEP and St. Johns River Water Management District at a meeting on March 15, 2001. Following review of further information on the Landfill runoff source, consideration can be given to its use and further discussions will be held with Orange County. It should be noted that the 2.91 mgd referred to is the cooling tower makeup water requirement that is reclaimed water provided by the Orange County Eastern

Regional Water Reclamation Facility. Please refer to the applicant's response to SJRWMD Question 1 for additional discussion of this subject.

8. *This is referred to as a zero discharge facility. Zero must refer to surface water discharge because it does not appear to be an IW definition of zero discharge – unless the makeup pond is lined. Besides groundwater and makeup well water, the makeup pond may receive any and all of the following:*

   a. *2.9 mgd DW effluent*
   b. *0.369 mgd effluent from Cooling Tower Blowdown Treatment System (effluent from crystallization system). This should probably be a good water quality, but I do not see an analysis.*
   c. *0.038 mgd from the boiler blowdown. (The text states the blowdown water will be routed to the Stanton A cooling tower for reuse. Will it be "routed" through the makeup pond?)*
   d. *? mgd from the gas desulfurization system (verbal information from GK in Air Section) that came from the Recycle Basin which receives:*

      *(1) 0.015 mgd effluent from an oil/water separator which receives wastewater from floor drains.*
      *(2) 0.012 mgd effluent from R/O from the demineralizer*
      *(3) wash down water*

   e. *? mgd. There is also an ash system that receives Recycle Basin water, but I am not sure if there is effluent and if it returns to this system.*

   *If these waste streams go to the makeup pond, I would like these to be shown on a water balance even though the wastewater streams in the pond may be so diluted by the DW effluent and the groundwater that there are no groundwater quality problems.*

   **Response:** Only the 2.9 mgd of DW from Orange County will be sent to the make-up pond. Cooling tower blowdown treatment distillate and boiler blowdown will go directly to the cooling tower under normal operations. Water for the Units 1 and 2 desulfurization and ash handling systems is taken from the recycle basin as covered in the Units 1 and 2 Site Certification Applications. All of these streams are shown on the attached water balances.

9. *Rainwater on transformers is skimmed then water goes to storm water pond. Is this tanks or IW?*

   **Response:** The rainwater released from the transformer area after verification of no contamination is characterized as Industrial Wastewater. It will be released to the site storm water drainage system if clean or directed to the oil-water separator.

10. *The submittal said that they would complete Form 2CG for Industrial Waste application. I did not see it.*

**Response:** Form 2CG was not included in the SSCA. The decision not to submit this form was based upon correspondence with FDEP. Black & Veatch had sought clarification prior to filing the SSCA as to whether a form was needed for the changes being made to the industrial wastewater treatment system or whether a narrative describing the wastewater system changes would be sufficient. Black & Veatch also asked, if a form was required, which one should be used? After failing to receive a definitive response from the Department, it was assumed that a narrative would be sufficient. The system is described in detail in Section 3.6 of the SSCA. A revised water mass balance (Figure 3.5-1) was included in the SSCA First Amendment submitted on March 8, 2001, and an updated version is attached as OUC waste water diagram, rev. 9.

11. *DW goes to a septic tank.*

**Response:** The sanitary wastewater for Stanton A will be routed to a new septic tank and absorption field and will meet state and local requirements.

12. *The quarterly data submitted uses a lot of "BDLs." The use is inconsistent. A parameter like Mercury will have a "<" for a couple of quarters then a "BDL" in the same quarter that other parameters have "<" symbols. Will ask for the lab sheets. If these detection limits are OK, we may be able to delete some parameters.*

**Response:** The lab data sheets have been included in the Sufficiency Response as Attachment A.

13. *A considerable amount of waste is hauled. Who regulates the hauling?*

**Response:** All wastes hauled from the plant site will be coordinated with the appropriate contractors to assure that all applicable regulations are met. On-site waste disposal is coordinated through the OUC Environmental Department.

14. *Please provide copies of the chemistry laboratory bench sheets for the ground water monitoring data for the 14 monitoring wells for the years 1999 and 2000.*

**Response:** The chemistry laboratory bench sheets for the ground water monitoring data for the 14 monitoring wells for 1999 and 2000 are included in the Sufficiency Response as Attachment A.

15. *Some of the monitoring well information was missing for the 4th quarter of 2000. Were the wells dry? Please clarify.*

**Response:** The chemistry laboratory bench sheets for the ground water monitoring data for the 14 monitoring wells for 1999 and 2000 are included in the Sufficiency Response as Attachment A.

16. *The Central District does not have any record of the well completion information on the monitoring wells. Please provide copies of the Well Completion Report Forms for each monitoring well. If these forms were not included in the permit, please fill out copies of the attached forms and submit them to the Department with well construction diagrams.*

**Response:** The applicants are not able to provide copies of the original Well Completion Report Forms for each monitoring well at this time. Consequently, new Well Completion Report Forms are currently being completed and will be submitted to the FDEP Central District as soon as possible. Well construction diagrams will be included in the submittal.

17. *Please revise the Water Balance (Figure 3.5-1) to include all of the wastewater streams going to the reuse basin and the make-up pond. Please show the recycle basin water going to Gas Desulfurization and Ash Systems and the return effluent, if any.*

**Response:** The attached revised water mass balances illustrate all new facilities and all new and existing wastewater streams going to the reuse basin and the make-up pond. The Units 1 and 2 desulfurization and ash systems are included in the existing facility's mass balance.

18. *Please sample the make-up pond, and the reuse basin for the parameters required in the quarterly ground water sampling plus TRPH.*

**Response:** The samples have been collected and analyzed. The preliminary report is included as Attachment B.

19. *For each waste stream in the expansion, please sample the correlative waste stream in the existing system for the parameters required in the quarterly ground water sampling plus TRPH.*

***Response:*** The samples have been collected and analyzed. The preliminary report is included as Attachment B.

20. *Please provide a copy of an analysis of brine concentrator wastewater from a similar existing system. At a minimum, the analysis shall include the primary standards for metals.*

**Response:** The brine concentrator system produces no wastewater stream. It is a closed loop process. The only process waste from the brine concentrator system is crystallizer salt that is encapsulated in the onsite landfill. Processed water is reused onsite.

21. *The scales for the monitoring well location maps are too small to accurately measure distances. Please show all of the monitoring wells on site plans with a scale similar to the Boring Location Map (Figure 2.3-4). Please include the locations of the Floridan Supply Wells as well.*

**Response:** The attached Black & Veatch drawing #8927-ISTU-S1010 shows all of the monitoring well locations and Floridan Supply wells.

22. *Please provide a scaled cross section through the reuse basin and the make-up pond.*

**Response:** These facilities were licensed with the Unit 1 Site Certification. Diagrams taken from the Unit 1 Site Certification Application are included and depict the recycle basin and make-up water supply storage pond.

23. *If there are historic staff guage readings for the ponds, please provide the data for 2000.*

**Response:** Historic staff gauge readings for the ponds for the year 2000 are attached.

24. *Please provide a data table for the monitoring wells, which includes:*
    a. *Ground surface elevations.*
    b. *Top of casing elevations.*
    c. *Below top of casing depth for the years 1999 and 2000.*
    d. *Ground water elevations for the years 1999 and 2000.*

**Response 24a:** See Response 16.
**Response 24b:** See Response 16.
**Response 24c:** See Response 16.
**Response 24d:** Ground water elevations for 1999 and 2000 are attached.

25. *Please be advised that currently the ground water is being monitored with the same parameters for both industrial waste streams and solid waste disposal sites. In reality, this is not necessary. Accordingly, based on the characterization of all industrial waste streams, please propose a separate Ground Water Monitoring Plan for addressing wastewater discharges into the reuse basin and make-up pond.*

*Please also be advised that a proposal for the revised Ground Water Monitoring Plan must include a provision of incorporating additional monitoring wells especially around the make-up pond as well as the reuse basin, along with appropriate parameters to be monitored in the ground water.*

*It may also be noted that all new compliance monitoring wells shall be proposed not more than 100 feet from the discharge basin/ponds.*

**Response:** A tour of the existing Stanton Energy Center facility and the proposed footprint of Stanton A was conducted on Tuesday, April 3, 2001, with representatives of FDEP Central District industrial wastewater and groundwater sections. The focus of this meeting was to clarify the design of the water and wastewater streams for the Stanton facility. The water/wastewater system infrastructure was designed and installed during the construction of Stanton Unit 1. Drawings that describe the water/wastewater system infrastructure are included as Attachment C. The drawings are described below:

Figure 5-17 is a simplified flow diagram for the makeup water supply storage pond for current and future units of this facility. The function of this pond is to store cooling tower make up and site drainage. It is a 93-acre pond. Inflows to this pond are treated sewage effluent from the Orange County easterly sub-regional plant, on site sewage treatment plant effluent, runoff from site drainage, and precipitation. Outflows from this pond are evaporation, seepage, and makeup to the plant cooling towers. Water quality analysis is provided from a recent sample of the pond and year 2000 quarterly results. The quality of this pond water analysis demonstrates that this pond does not have adverse impact to the groundwater. The applicants feel no groundwater monitoring is required.

Figure 5-20 is a simplified flow diagram of the recycle basin. The function of this pond is to store wastewater for use as makeup to the ash handling and scrubber systems. It is a 15-acre segmented lined pond. Inflows to this pond are blowdown from the cooling tower system, miscellaneous plant drains, neutralization basin, precipitation, overflow from the coal storage runoff pond, and active combustion waste area runoff pond. Outflows from this pond are makeup to the Cooling Tower Blowdown Treatment facility, ash handling, scrubber systems and evaporation. Additionally, this water is used for air heater, boiler and precipitator cleaning.

Figure 5-14 is a simplified flow diagram for the scrubber system. Water inflows to this system are from the recycle basin, service water, and service water treatment wastewater sump. Outflows from this system are evaporation and solids to solid waste disposal.

Figure 5-12 is a simplified flow diagram of the ash handling system. Water inflows to this system are from the recycle basin and service water. Outflows from this system are evaporation and solids to solid waste disposal.

Figure 3-1 is a simplified flow diagram of the chemical waste drainage. Demineralizer and condensate polisher regeneration wastes, chemical cleaning wastes and miscellaneous chemical drains are inflows to the neutralization basin. Outflow from this basin is to the recycle basin.

Figure 5-19 is a simplified flow diagram of the coal storage area runoff pond. It is a 10.4-acre segmented lined pond. The function of this pond is to store coal storage area runoff. Outflow from this pond is to the recycle basin.

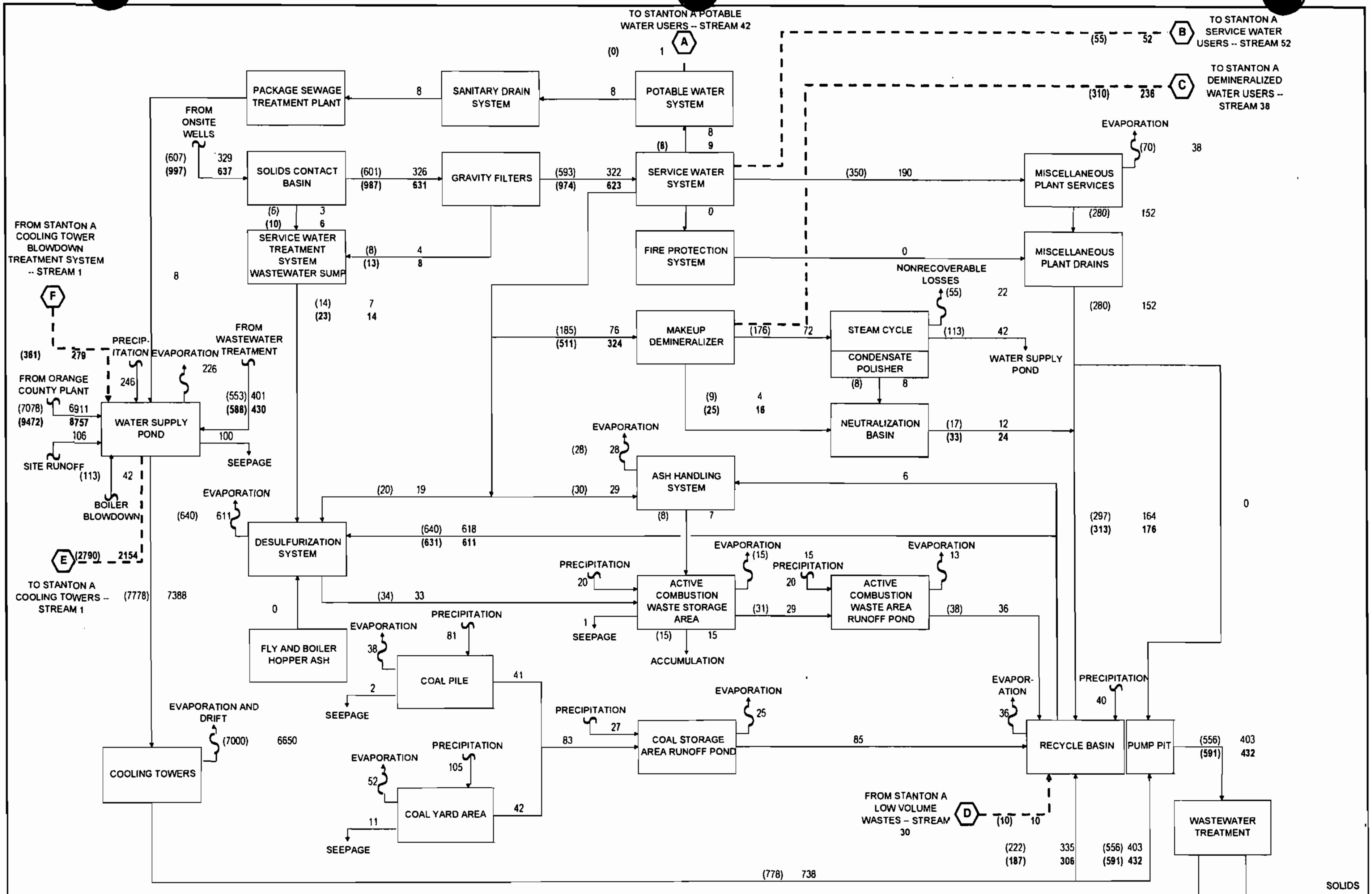
Figure 5-18 is a simplified flow diagram of the active combustion waste area runoff pond. It is a 5 acre lined pond. The function of this pond is to store active combustion waste area runoff. Outflow from this pond is to the recycle basin.

The applicants will work with the FDEP to revise groundwater sampling parameters as needed.

26. *When the Site Certification is issued for the requested modification, the Ground Water Section, Central District, Orlando must receive one copy of Ground Water Monitoring reports for industrial wastewater discharges.*

**Response:** OUC will add the Central District's Ground Water Section to the distribution list.

Stanton Unit 1 and 2
Stanton A
Water Mass Balances



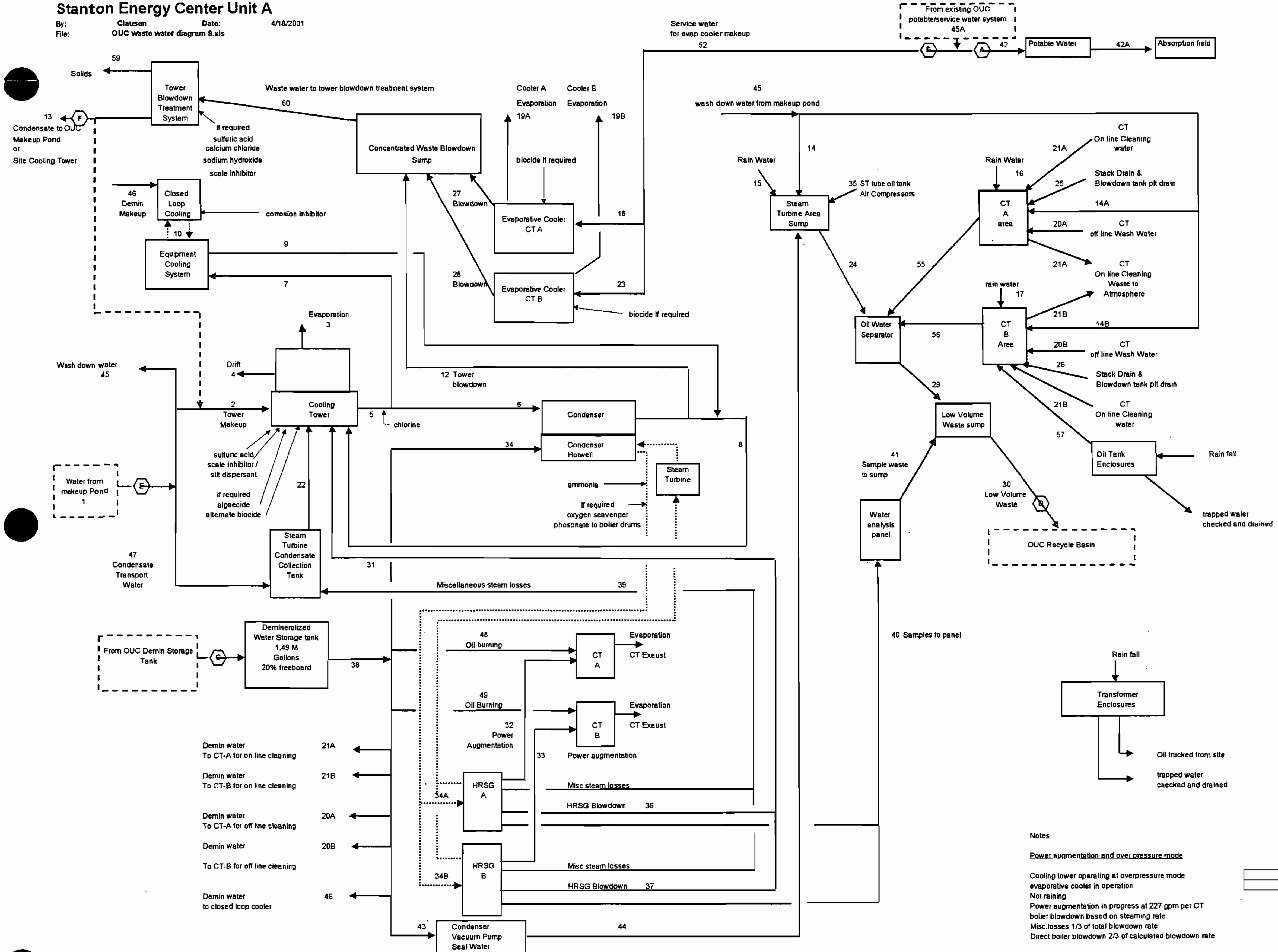

**FLOWS AND FLOW PATHS FOR UNITS 1 AND 2 ARE BASED ON FIGURE 3.5-1 SUBMITTED WITH THE UNIT 2 SITE CERTIFICATION APPLICATION SUBMITTED ON 3/15/91**

NOTE:
1. ALL FLOWS ARE EXPRESSED IN GALLONS PER MINUTE.
2. INTERFACES WITH STANTON A WATER MASS BALANCE INDICATED BY DASHED LINES AND ⬡ SYMBOL.
3. PEAK FLOWS ARE INDICATED BY PARENTHESES.
4. BOLD FLOWS INDICATE CHANGES ASSOCIATED WITH THE ADDITION OF UNIT A.

| | | | | |
|---|---|---|---|---|
| BLACK & VEATCH | ORLANDO UTILITIES COMMISSION STANTON ENERGY CENTER COMBINED CYCLE PROJ. | Project 049857.0030 | Drawing | Rev C |
| Eng: / Dwg: JDC | WATER MASS BALANCE INTERFACES WITH EXISTING FACILITIES | | | |
| Check: / Date: 4/18/2001 | | | | |

## Stanton Energy Center Unit A

By: Clausen Date: 4/18/2001
File: OUC waste water diagram 9.xls




| Line No. | Stream<br>Flows are block flows unless otherwise noted | Average Flow based on plant operation gpm | Max Flow Power Aug over press gpm |
|---|---|---|---|
| E 1 | Makeup water from OUC makeup pond | 2154.4 | 2790.0 |
| 2 | Cooling tower makeup | 2101.6 | 2735.0 |
| 3 | Cooling tower evaporation | 1922.9 | 2495.0 |
| 4 | Cooling tower drift | 2.6 | 2.7 |
| 5 | Circulating water pump discharge | 128250.0 | 135000.0 |
| 6 | Condenser inlet | 118750.0 | 125000.0 |
| 7 | Cooling water to equipement cooling water system | 9500.0 | 10000.0 |
| 8 | Condenser and service water cooler discharge to tower | 127977.9 | 134646.0 |
| 9 | Equipment cooling system return hot water | 9500.0 | 10000.0 |
| 10 | Closed loop cooling flow | 9025.0 | 9500.0 |
| 11 | spare | 0.0 | 0.0 |
| 12 | Cooling tower blowdown | 272.1 | 354.0 |
| F 13 | Waste treatment condensate to OUC makeup pond or site tower | 278.6 | 360.9 |
| 14 | Makeup pond water to steam turbine area for wash down | 0.2 | 0.0 |
| 14A | Makeup pond water to CT-A area | 0.2 | 0.0 |
| 14b | Makeup pond water to CT-B area | 0.2 | 0.0 |
| 15 | Rain water to steam turbine area | 0.1 | 0.0 |
| 16 | Rain water to CT-A area | 0.0 | 0.0 |
| 17 | Rain water to CT-B area | 0.0 | 0.0 |
| 18 | Makeup water to CT-A evaporative cooler | 26.1 | 27.4 |
| 19A | CT- A evaporative cooler evaporation | 22.8 | 24.0 |
| 19B | CT- B evaporative cooler evaporation | 22.8 | 24.0 |
| 20A | CT-A off line cleaning wash water | 0.1 | 0.0 |
| 20B | CT-B off line cleaning wash water | 0.1 | 0.0 |
| 21A | CT-A on line wash water | 0.5 | 0.0 |
| 21B | CT-B online wash water | 0.5 | 0.0 |
| 22 | Steam Turbine collection tank to cooling tower basin | 66.7 | 75.4 |
| 23 | Water to CT-B evaporative cooler | 26.1 | 27.4 |
| 24 | Steam turbine area to oil water separator | 0.3 | 0.0 |
| 25 | CT A stack drain and blowdown tank pit drain | 0.0 | 0.0 |
| 26 | CT A stack drain and blowdown tank pit drain | 0.0 | 0.0 |
| 27 | CT-A evap cooler blowdown | 3.3 | 3.4 |
| 28 | CT-B evap cooler blowdown | 3.3 | 3.4 |
| 29 | Oil water separator to low volume sump | 0.8 | 0.0 |
| D 30 | Low volume waste to OUC recycle basin | 10.3 | 10.0 |
| 31 | Total block boiler blow down | 29.3 | 41.4 |
| 32 | Power augmentation to CT A | 64.8 | 227.0 |
| 33 | Power augmentation to CT B | 64.8 | 227.0 |
| 34 | Makeup to Condenser Hotwell | 182.8 | 525.7 |
| 34a | Makeup for losses at HRSG A | 91.4 | 262.9 |
| 34b | Makeup for losses at HRSG B | 91.4 | 262.9 |
| 35 | Steam turbine lube oil tank and Air Compressors | 0.0 | 0.0 |
| 36 | HRSG A Blowdown to tower | 14.6 | 20.7 |
| 37 | HRSG B Blowdown to tower | 14.6 | 20.7 |
| C 38 | Demin. water to process | 235.5 | 525.7 |
| 39 | Total HRSG miscellaneous losses | 14.4 | 20.4 |
| 39A | HRSG A misc. losses | 7.2 | 10.2 |
| 39B | HRSG B misc. losses | 7.2 | 10.2 |
| 40 | Water analysis panel waste | 9.5 | 10.0 |
| 41 | Panel waste to low volume sump | 9.5 | 10.0 |
| A 42 | Potable water to block from potable water supply | 0.6 | 0.0 |
| 42A | Sewage to treatment from block | 0.6 | 0.0 |
| 43 | Condenser vacuum pump seal water makeup | 0.0 | 0.0 |
| 44 | Condenser vacuum pump seal water waste | 0.0 | 0.0 |
| 45 | washdown water | 0.6 | 0.0 |
| 45A | From existing OUC potable/service water system | 52.7 | 54.9 |
| 46 | Closed loop cooling water makeup | 0.0 | 0.0 |
| 47 | Condensate transport water | 52.3 | 55.0 |
| 48 | Demin water to CT- A during fuel oil burn | 25.8 | 0.0 |
| 49 | Demin water to CT- B during fuel oil burn | 25.8 | 0.0 |
| 50 | Spare | | |
| 51 | Fire Protection water to site | 0.0 | 0.0 |
| B 52 | Evap cooler makeup from OUC site | 52.1 | 54.9 |
| 53 | spare | | |
| 54 | spare | | |
| 55 | CT - A area sump to oil water separator | 0.3 | 0.0 |
| 56 | CT - B area sump to oil water separator | 0.3 | 0.0 |
| 57 | Oil storage tanks to CT - B area sump | 0.0 | 0.0 |
| 58 | Spare | | |
| 59 | Solids to land fill pounds per minute | 7.7 | 10.2 |
| 60 | Conc. Waste sump to blowdown treatment | 278.6 | 360.9 |
| | in | 2442.8 | 3370.6 |
| | out | 2442.8 | 3370.6 |

Notes

Power augmentation and over pressure mode

| | | |
|---|---|---|
| Cooling tower operating at overpressure mode | 8 | cycles |
| evaporative cooler in operation | 8 | cycles |
| Not raining | | |
| Power augmentation in progress at 227 gpm per CT | | |
| boiler blowdown based on steaming rate | 1 | % |
| Misc.losses 1/3 of total blowdown rate | | |
| Direct boiler blowdown 2/3 of calculated blowdown rate | | |

Blowdown

| | | |
|---|---|---|
| hot reheat | 719782 | |
| Lp admission | 20469 | |
| Main steam | 803371 | |
| | 1543622 | #/hr |
| | 30.87244 | gpm |

Average Flow Based on plant operation

operation factor 0.95
Normal operation a function of power factor and power aug. and oil burning
power augmentation operation 2500 hours
oil burning 1000 hours
evaporative cooler in operation 12 hours per day
Assume washdown of 100 gpm for 60 minutes per week (20 minutes per area)
rain water 48.11 inches annual

| | | |
|---|---|---|
| steam turbine sump | 1556 | ft2 |
| CT A sump | 220 | ft2 |
| CTB sump | 220 | ft2 |

on line cleaning 780 gallons once per day exausted to atmosphere
off line cleaning 2430 gallons once per month trucked from site
assume 30 gallons per day per person, 30 persons/day
1% boiler blowdown based on steaming rate
Misc.losses 1/3 of total blowdown rate
Direct boiler blowdown 2/3 of calculated blowdown rate
Interconnections with Stanton Units 1 & 2 are indicated by

Figure 3.5-1

# Recycle Basin Description

coal pile and yard area are assumed to have pervious surfaces and represent 24 per cent and 60 per cent of the total coal storage area, respectively, 5 which includes the coal pile, coal yard and CSA runoff pond. The CSA runoff pond will have a surface area of approximately 10.4 acres (16 per cent of coal storage area), with an embankment length of 4,100 feet and is designed to retain without discharge the surface runoff and direct pond 5 precipitation from a 24-hour event having a recurrence interval of 10 years. The 10-year, 24-hour precipitation event is considered to be 7.5 inches as indicated in Section 2.6. The capacity of the CSA runoff pond was determined by assuming an average of 50 per cent (3.75 inches) of the design precipitation 5 would occur as surface runoff. This corresponds to a runoff curve number (U.S. Soil Conservation Service) of 67. Runoff from precipitation exceeding the 10-year, 24-hour event will be directed to the recycle basin. 5

The maximum design water surface elevation within the CSA runoff pond is 79.5 feet, msl. This elevation would result from surface runoff and 5 direct pond precipitation during a 10-year, 24-hour event or greater. The pond bottom will be at Elevation 75 feet, msl and will consist of a one-foot thick layer of compacted material providing cover for a 6-inch thick highly impermeable liner. Soil-cement will be utilized to provide slope protection. A section of the proposed CSA runoff pond embankment is shown on Figure 3.10-3.

Runoff and direct precipitation retained within the CSA runoff pond will be directed to the recycle basin to be used as makeup for the flue gas desulfurization and ash handling systems. Controlled drainage of the CSA runoff pond to the recycle basin will be accomplished through the use of a buried pipeline. 5

### 3.10.3 Recycle Basin

#3 The recycle basin, shown on Figure 3.10-1, will be lined to control seepage loss. The recycle basin is designed to provide for the temporary storage of effluents from the neutralization basin and wastewater from the miscellaneous plant drains. The recycle basin will also receive intermittent flows from the coal storage area runoff pond and the active combustion waste area runoff pond. The recycle basin will provide makeup to the desulfurization and ash handling systems. Blowdown from the cooling tower will provide makeup to the recycle basin as required to maintain proper water surface elevation.

The recycle basin will have a surface area of approximately 15 acres with an embankment length of 5,200 feet. The operating water surface elevation within the recycle basin will be 75 feet, msl corresponding to an 5
average depth of 5 feet. The pond bottom will be at Elevation 70 feet, msl and will consist of a 1-foot thick layer of compacted material providing cover for a 6-inch thick highly impermeable liner. Soil-cement will be utilized to provide slope protection. A section of the proposed recycle basin embankment is shown on Figure 3.10-4.

Compacted site fill will be placed to Elevation 80 feet, msl within the area. The site fill material will be sloped away from the perimeter of 5
the recycle basin to prevent surface runoff from entering the basin. Surface runoff from the area will be directed to the makeup water supply storage pond.

### 3.10.4 Active Combustion Waste Area Runoff Pond

Surface runoff from the active portion of the combustion waste storage area will be directed to the lined active combustion waste area runoff pond (ACWA runoff pond) shown on Figure 3.10-1. Runoff from both the developed and undeveloped portions of the combustion waste storage area will be directed to natural drainage systems within the area. The developed portion of the waste storage area is defined as a formerly active portion which has been reclaimed by covering with topsoil and reestablished with vegetation. The undeveloped portion is that which has not yet been utilized for combustion waste storage. The undeveloped portion of the area will be reseeded subsequent to site borrow operations.

Approximately 312 acres have been allocated for combustion waste storage. This area will be developed in active increments of approximately

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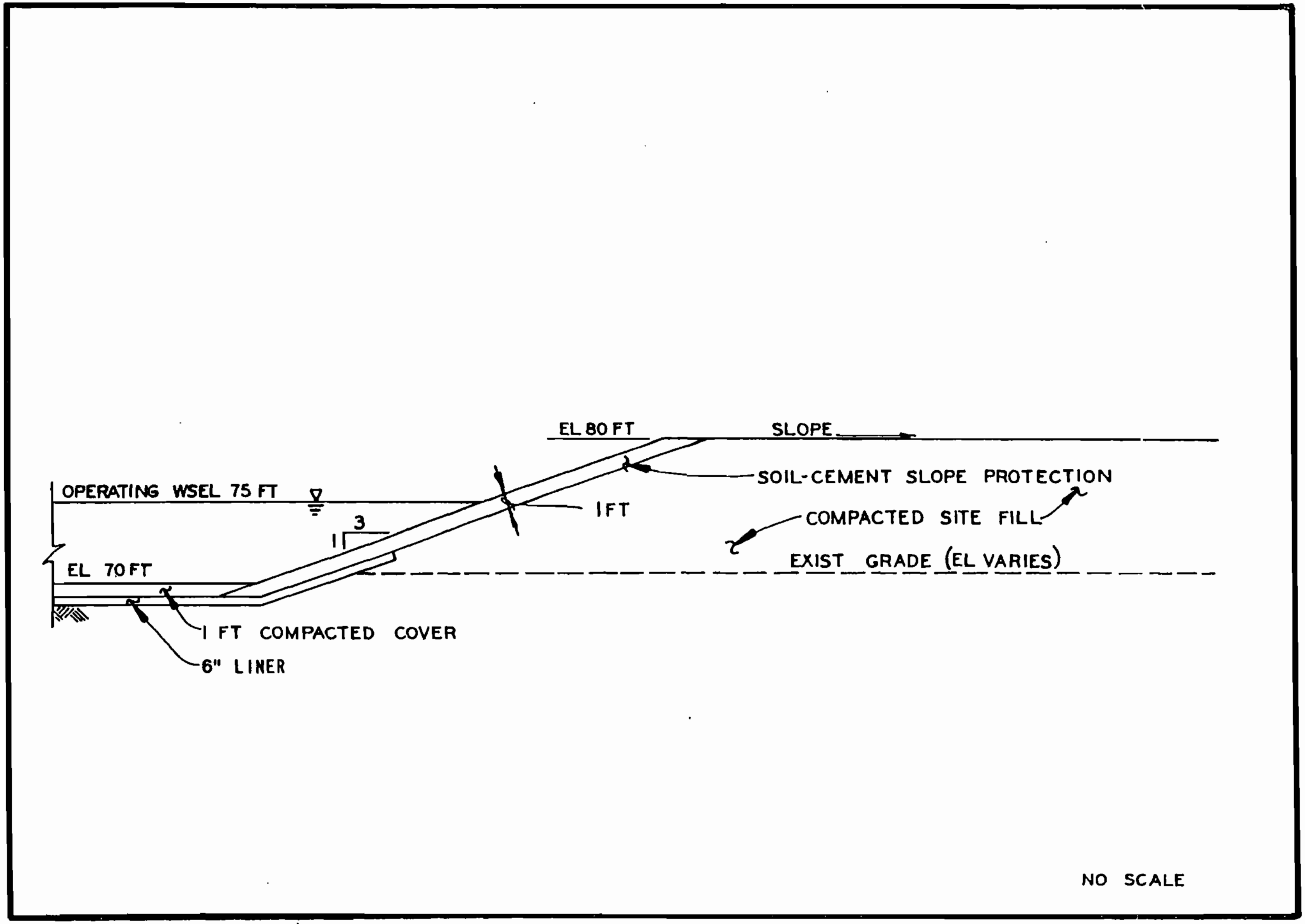



5

FIGURE 3.10-4. RECYCLE BASIN EMBANKMENT SECTION

13

# Neutralization Basin Description

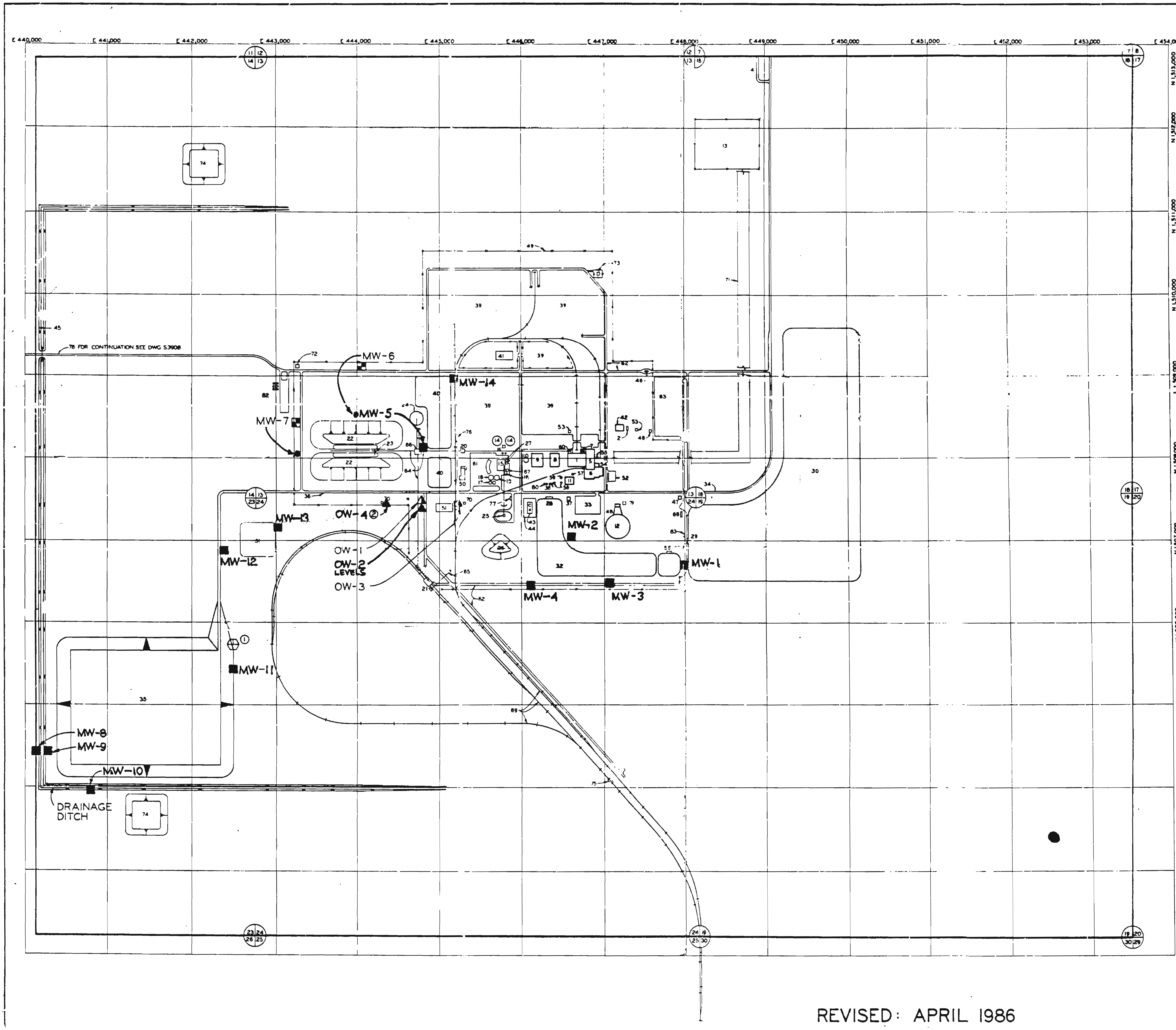
### 3.5.8 Miscellaneous Chemical Drains

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

### 3.5.9 Neutralization Basin

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

Ground Water Monitoring Well Locations
Drawing 8927-ISTU-S1010




## FACILITIES LEGEND

1 UNIT 1 STEAM GENERATOR
2 FIRST AID TRAILER
3
4 ALTERNATE ACCESS ROAD
5 TURBINE ROOM
6 ADMINISTRATION AND PLANT SERVICES BUILDING
7 CONTROL CENTER BUILDING
8 PRECIPITATOR
9 AIR QUALITY CONTROL BUILDING
10 CHIMNEY
11 WATER MANAGEMENT BUILDING
12 COOLING TOWER
13 SUBSTATION
14 THICKENER
15 SLUDGE CONDITIONING BUILDING
16 FLY ASH SILO
17 ASH DEWATERING TANK
18 ASH SETTLING TANK
19 ASH WATER STORAGE TANK
20 COAL CRUSHER BUILDING
21 COAL CAR UNLOADING BUILDING
22 COAL STORAGE AREA
23 STACKER RECLAIMER
24 EMERGENCY STOCKOUT AND RECLAIM
25 SCRUBBER ADDITIVE RECLAIM
26 SCRUBBER ADDITIVE STORAGE
27 SCRUBBER ADDITIVE STORAGE TANK
28 SCRUBBER MAKEUP WATER PUMP STRUCTURE
29 CIRCULATING WATER MAKEUP PUMP STRUCTURE
30 MAKEUP WATER SUPPLY STORAGE POND
31 ACTIVE COMBUSTION WASTE AREA RUNOFF POND
32 RECYCLE BASIN
33 ADMINISTRATION AND PLANT SERVICES PARKING LOT
34 MAIN PLANT ACCESS ROAD
35 COMBUSTION WASTE STORAGE AREA
36 COMBUSTION WASTE HAUL ROAD
37 COMPRESSED GAS STORAGE BUILDING
38 WATER STORAGE PUMP BUILDING
39 CONSTRUCTION LAYDOWN AREA
40 COAL STORAGE AREA RUNOFF POND
41 CONSTRUCTION WAREHOUSE
42 CONSTRUCTION OFFICE BUILDING
43 FUEL OIL STORAGE
44 OIL SPILL CONTAINMENT BERM
•45 CONCRETE BATCH PLANT (OFFSITE)
46 GUARD STATION
47 SECURITY BUILDING
48 CIRCULATING WATER PUMP STRUCTURE
49 SECURITY FENCE
50 YARD SERVICES BUILDING
51 PERMANENT WAREHOUSE
52 VISITORS PARKING LOT
•53 CONSTRUCTION TOILET BUILDING
•54 LUBE OIL STORAGE ROOM
55 GENERATOR TRANSFORMER AREA
56 WASTEWATER RETURN PUMP STRUCTURE
57 [illegible]
58 SERVICE WATER STORAGE TANKS
59 DEMINERALIZED WATER STORAGE TANK
60 CONDENSATE STORAGE TANKS
61 COMBUSTION WASTE LOADING AREA
62 PLANT SERVICE ROADS
63 CONSTRUCTION PARKING
64 YARD COAL CONVEYOR
•65 FUTURE YARD SCRUBBER ADDITIVE CONVEYOR
66 COAL TRANSFER STRUCTURE
67 LIME STORAGE SILO
68 SEWAGE TREATMENT PLANT
69 RAILROAD
70 WELL WATER PUMP HOUSE
•71 SITE TRANSMISSION CORRIDOR
72 TEMPORARY ACCESS ROAD GUARDHOUSE
•73 CONSTRUCTION POWER SUBSTATION
74 TOPSOIL COVER STOCKPILE
75 TRACK SCALE
•76 FUTURE LIME UNLOADING BUILDING
77 TRUCK SCALE
78 TEMPORARY ACCESS ROAD
79 CIRCULATING WATER CHEMICAL FEED BUILDING
80 EMERGENCY GENERATOR BUILDING
81 THICKENER PUMP BUILDING
•82 TEMPORARY CONSTRUCTION PARKING AND CONTRACTOR TRAILER AREA
83 SUS BUILDING

## LEGEND

△ EXISTING OBSERVATION WELLS
■ NEW GROUND WATER MONITORING WELL
⊕ FUTURE GROUND WATER MONITORING WELL

## NOTES

1. TYPICAL PLACEMENT OF FUTURE ADDITIONAL MONITORING WELLS, ONE PER CELL, 300 FOOT SPACING
2. OBSERVATION WELL OW-4 WILL BE USED AS A MONITORING WELL
3. PIEZOMETER REMOVED DURING CONSTRUCTION
4. MW-5 AND MW-6 WILL BE LOCATED WITHIN 100 FEET OF COAL STORAGE AREA
5. MW-11 AND MW-12 WILL BE LOCATED WITHIN 100 FEET OF THE COMBUSTION WASTE STORAGE AREA
6. MW-13 AND MW-14 WILL BE LOCATED WITHIN 100 FEET OF THEIR [illegible]

REVISED: APRIL 1986

| NO | DATE | REVISIONS AND RECORD OF ISSUE | BY | CHK | APP | FLM |
|---|---|---|---|---|---|---|

400' 200' 0 400' 800'

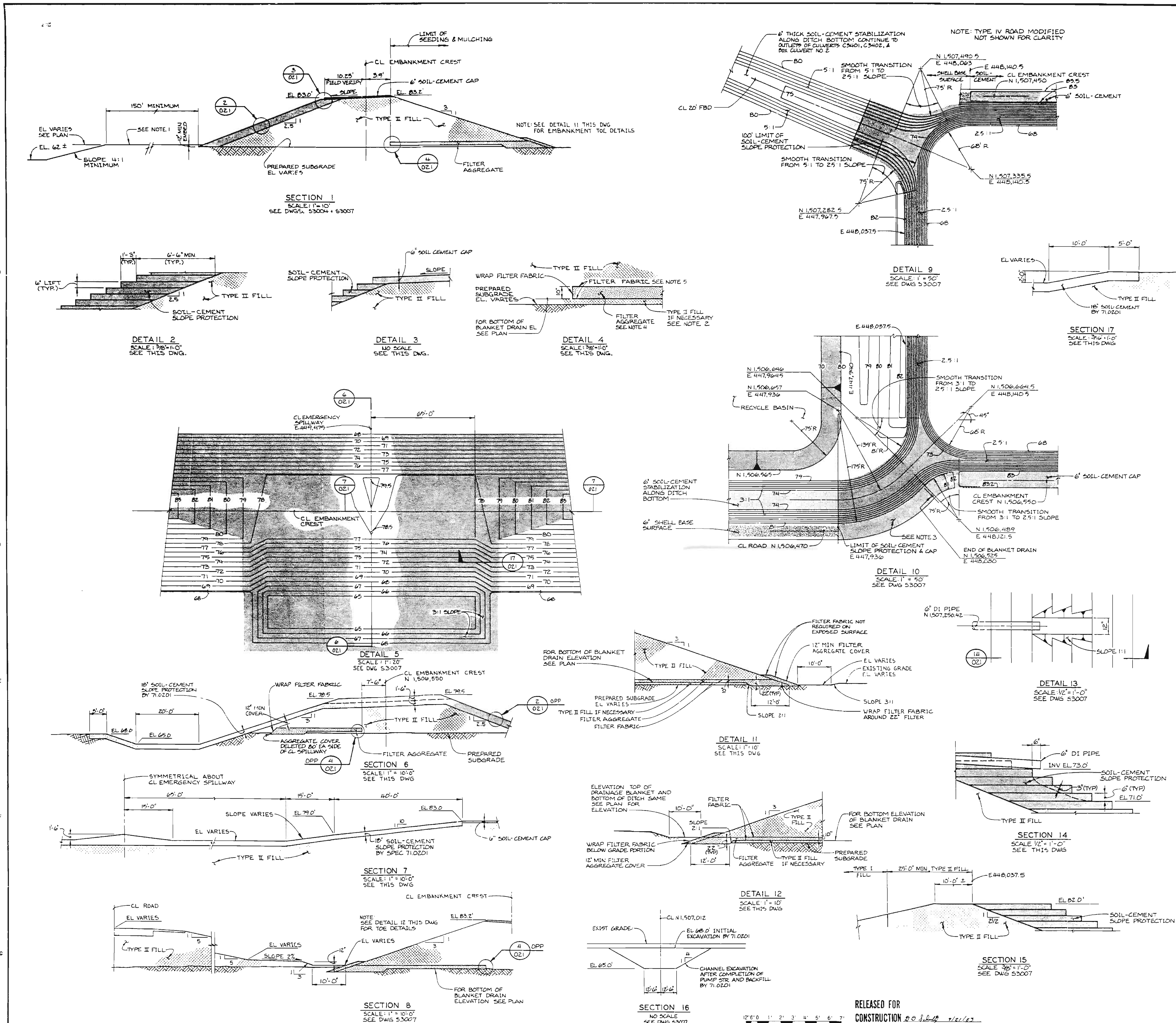
[illegible] THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA
SIGNED
DATE REG NO.

BLACK & VEATCH CONSULTING ENGINEERS
ENGINEER / DRAWN / CHECKED / DATE

ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER - UNIT 1
GROUND WATER MONITORING WELLS

PROJECT / DRAWING NUMBER: 8927 - ISTU - S1010
CODE
AREA

Makeup Pond and Recycle Basin Section Drawings
8927-ISTU-S3021
Figure 3.10-2
Figure 3.10-4




## NOTES

1. THE POND BOTTOM PERIMETER SHALL BE GRADED SMOOTH AND COMPACTED TO 95 PERCENT OF MAX DENSITY AT THE SURFACE.
2. AFTER PREPARATION OF SUBGRADE. TYPE II FILL MAY BE REQUIRED AT SOME LOCATIONS TO CONSTRUCT BLANKET AT ELEVATIONS INDICATED ON THE DRAWINGS.
3. GRADUAL TRANSITION FROM TYPE IV ROAD MODIFIED AS SHOWN IN SECTION 19 DWG S3203 (E447,936) TO TYPICAL EMBANKMENT CREST (E448,121.5).
4. THE AGGEGATE FILTER MATERIAL SHALL BE BACK DUMPED AND SPREAD IN ONE UNIFORM LIFT MAINTAINING THE DESIGN FILTER THICKNESS. DUMP TRUCKS AND SPREADING EQUIPMENT SHALL WORK FROM THE TOP OF THE AGGREGATE FILTER AND SHALL NOT COME IN DIRECT CONTACT WITH THE ENGINEERING FILTER FABRIC. OVERSTRESSING THE AGGREGATE MATERIAL SHALL BE AVOIDED BY USING EQUIPMENT THAT EXERTS ONLY MODERATE PRESSURES. THE AGGREGATE FILTER SHALL BE COMPACTED BY TRACKING CRAWLER TYPE EQUIPMENT OR PASSING VIBRATORY COMPACTORS HAVING MODERATE WEIGHT OVER THE MATERIAL UNTIL ACHEIVING A DENSITY OF NO LESS THAN 70 PERCENT OF RELATIVE DENSITY AS DETERMINED BY ASTM D2049.
5. THE ENGINEERING FILTER FABRIC SHALL BE OVERLAPPED A MINIMUM OF 12 INCHES AT FABRIC SPLICES WHEN BEING PLACED IN A HORIZONTAL POSITION. AN OVERLAP OF 24 INCHES SHALL BE USED AT FABRIC SPLICES WHEN THE FABRIC IS IN A SLOPED OR VERTICAL POSITION. SECURING PINS SHALL BE USED WHEN NECESSARY TO ENSURE PROPER ANCHORING OF THE FABRIC. THE FABRIC SHALL BE PROTECTED BY COVERING WITH AT LEAST 12 INCHES OF MATERIAL PRIOR TO COMPACTION. CAUTION SHALL BE USED WHEN PLACING MATERIAL OVER THE FILTER FABRIC TO PREVENT DAMAGE TO OR PUNCTURE OF THE FABRIC

RELEASED FOR CONSTRUCTION 9/21/83

| NO. | DATE | REVISIONS AND RECORD OF ISSUE | BY | CHK | APP |
|---|---|---|---|---|---|
| 8 | 12-16-88 | CONFORMED TO CONSTRUCTION RECORDS | BD | | |
| 7 | 2-6-85 | REVISED SPILLWAY DETAILS. SECT 1, ADD SECT 17 | TPP | | |
| 6 | 12-14-84 | DETAIL 5 ON HOLD, REVISED EMBANKMENT DETAILS | TPP | | |
| 5 | 8-9-84 | REVISED COORDINATE ON DETAIL 13 | TPP | | |
| 4 | 6-7-84 | REVISED SECTION 1, 11, & 12 DETAIL 13 | CTF | | |
| 3 | 4-4-84 | REVISED DETAILS AND ADDED NOTES | CTF | | |
| 2 | 9-21-83 | GENERAL REVISIONS | TPP | SRI | |
| 1 | 8-16-83 | GENERAL REVISIONS | CTF | TPP | |
| 0 | 7-19-83 | INITIAL ISSUE | CTF | TPP | |

SCALE: 1" = 10' / 1" = 20'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED
DATE 7-15-83 REG NO. 32245

BLACK & VEATCH CONSULTING ENGINEERS
ENGINEER T P PINTCKE — DRAWN MRG
CHECKED S R IHNOW — DATE 9-21-83

ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER - UNIT 1
SITEWORK - MAKEUP WATER POND
PLANS, SECTIONS, & DETAILS

PROJECT 8927 — DRAWING NUMBER ISTF-S3021 — REV 8
CODE
AREA

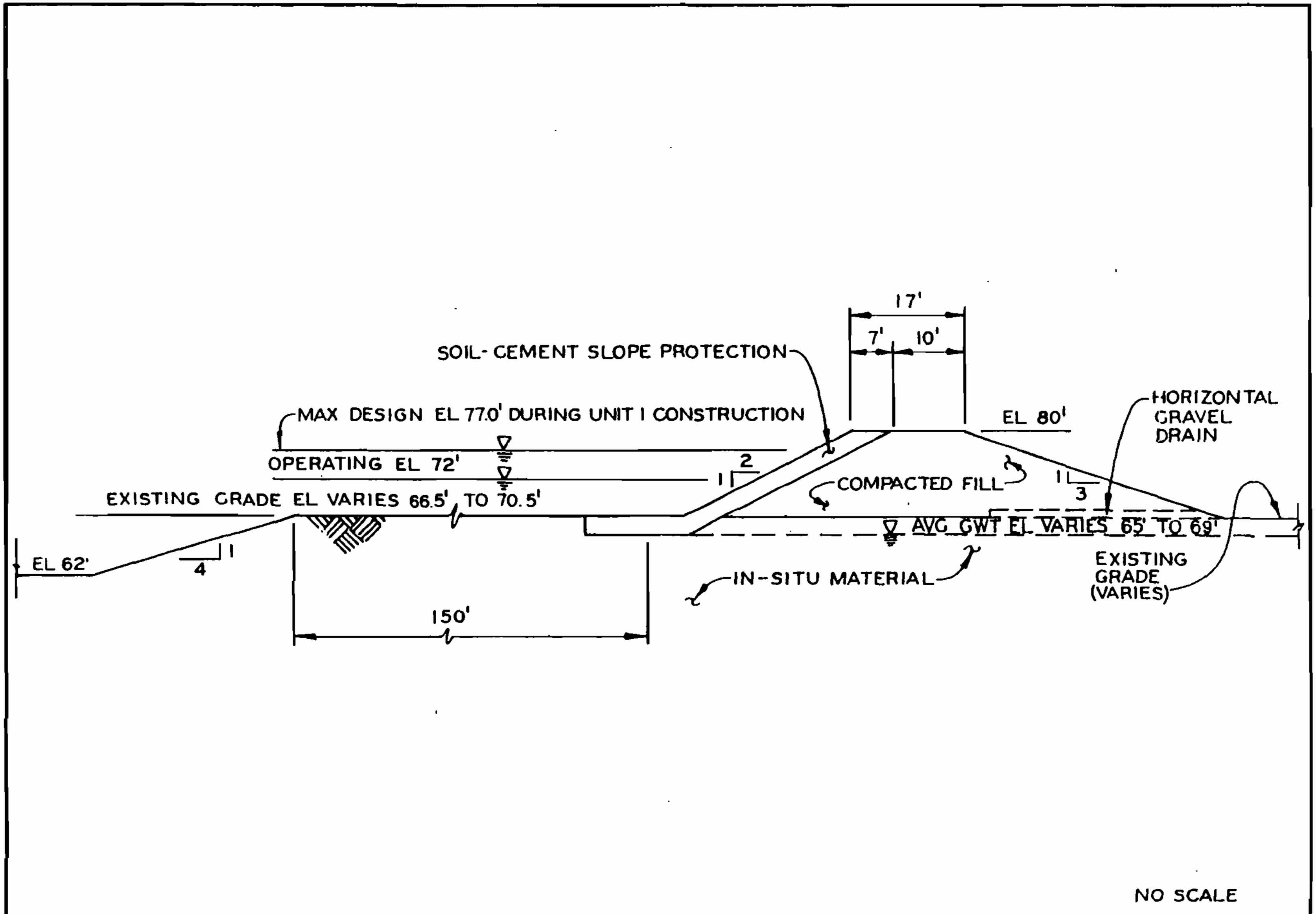
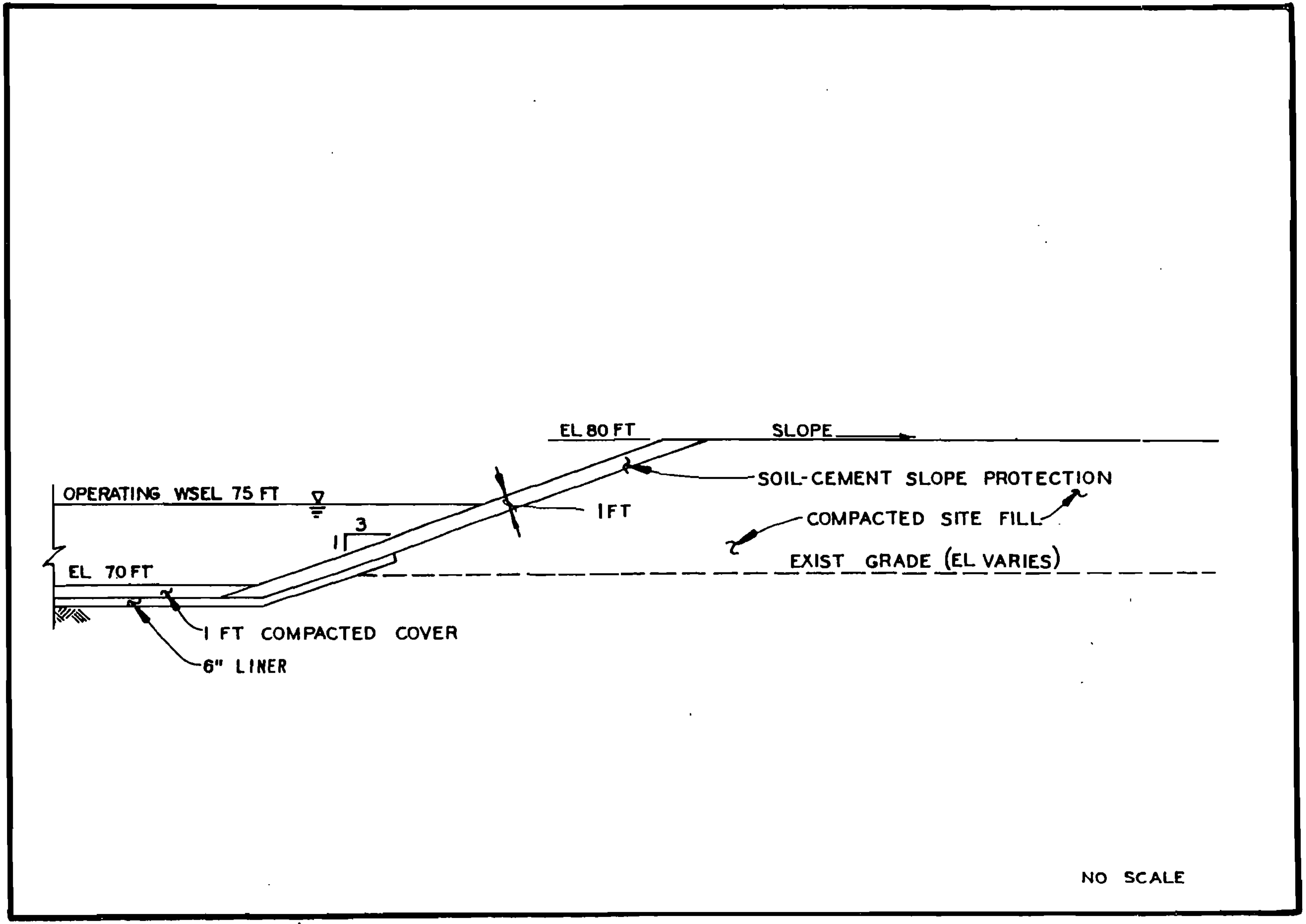



FIGURE 3.10-2. MAKEUP WATER SUPPLY STORAGE POND EMBANKMENT SECTION

#22

5

AMENDMENT 5
030382




5

#22 FIGURE 3.10-4. RECYCLE BASIN EMBANKMENT SECTION

Staff Gauge Readings
Year 2000

| STANTON ENERGY CENTER | | | | | | | |
|---|---|---|---|---|---|---|---|
| MAKEUP POND AND RECYCLE BASIN STAFF GAUGE READINGS FOR 2000 | | | | | | | |
| DATE | MAKEUP | RECYCLE | | | | | |
| | (FT) | (FT) | | | | | |
| 1/7/00 | 77.3 | 77.8 | | | | | |
| 1/14/00 | 77.3 | 77.7 | | | | | |
| 1/21/00 | 77.1 | 77.6 | | | | | |
| 1/28/00 | 76.9 | 77.2 | | | | | |
| 2/4/00 | 76.8 | 77.3 | | | | | |
| 2/11/00 | 76.5 | 77.8 | | | | | |
| 2/18/00 | 76.6 | 78 | | | | | |
| 2/25/00 | 76.9 | 78.2 | | | | | |
| 3/2/00 | 76.8 | 78.8 | | | | | |
| 3/9/00 | 76.9 | 78.5 | | | | | |
| 3/17/00 | 76.7 | 78.1 | | | | | |
| 3/24/00 | 77.1 | 78.3 | | | | | |
| 3/31/00 | 77.2 | 78.2 | | | | | |
| 4/7/00 | 77 | 78.3 | | | | | |
| 4/14/00 | 76.9 | 78.5 | | | | | |
| 4/21/00 | 76.9 | 78.3 | | | | | |
| 4/27/00 | 76.7 | 78.1 | | | | | |
| 5/5/00 | 76.7 | 77.7 | | | | | |
| 5/12/00 | 76.5 | 77.3 | | | | | |
| 5/19/00 | 76.1 | 76.7 | | | | | |
| 5/26/00 | 76.7 | 76.6 | | | | | |
| 6/2/00 | 75.2 | 76.4 | | | | | |
| 6/9/00 | 74.8 | 75.3 | | | | | |
| 6/16/00 | 74.4 | 75.3 | | | | | |
| 6/23/00 | 74.5 | 74.9 | | | | | |
| 6/30/00 | 75.6 | 75.8 | | | | | |
| 7/7/00 | 75.7 | 75.4 | | | | | |
| 7/14/00 | 76.9 | 75.1 | | | | | |
| 7/21/00 | 76.1 | 75 | | | | | |
| 7/28/00 | 76.8 | 76.1 | | | | | |
| 8/4/00 | 77 | 76 | | | | | |
| 8/11/00 | 76.9 | 75.3 | | | | | |
| 8/18/00 | 76.8 | 74.9 | | | | | |
| 8/25/00 | 76.8 | 74.8 | | | | | |
| 9/1/00 | 76.7 | 74.4 | | | | | |
| 9/8/00 | 76.5 | 75.6 | | | | | |
| 9/14/00 | 76.7 | 76 | | | | | |
| 9/22/00 | 77.2 | 76.6 | | | | | |
| 9/29/00 | 77.4 | 76.3 | | | | | |
| 10/6/00 | 77.6 | 77 | | | | | |
| 10/13/00 | 77.1 | 76.2 | | | | | |
| 10/20/00 | 77.1 | 75.1 | | | | | |
| 10/26/00 | 77.3 | 75.2 | | | | | |
| 11/2/00 | 77.3 | 75.1 | | | | | |
| 11/10/00 | 76.8 | 76.3 | | | | | |
| 11/17/00 | 77 | 76.5 | | | | | |
| 11/22/00 | 77.1 | 75.9 | | | | | |
| 12/1/00 | 76.9 | 75.8 | | | | | |
| 12/8/00 | 76.9 | 74.9 | | | | | |
| 12/15/00 | 77.1 | 74.7 | | | | | |
| 12/22/00 | 76.9 | 75.7 | | | | | |
| 12/29/00 | 77.1 | 76.4 | | | | | |

# Ground Water Elevations
1999-2000

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Stanton Energy Center | | | | | | |
| MONITOR WELL GROUNDWATER ELEVATIONS* | | | | | | | | |
| | 1999 | | | | 2000 | | | |
| MW | 1st QTR | 2nd QTR | 3rd QTR | 4th QTR | 1st QTR | 2nd QTR | 3rd QTR | 4th QTR |
| | (FT) | (FT) | (FT) | (FT) | (FT) | (FT) | (FT) | (FT) |
| 1 | 10.3 | 9.41 | 8.17 | 8.51 | 9.1 | 10.67 | 8.81 | NR |
| 2 | 6.84 | 5.41 | 4.39 | 4.21 | 5.4 | 6.08 | 5.08 | NR |
| 3 | 6.25 | 5.96 | 5.14 | 4.92 | 5.34 | 6.85 | 5.25 | NR |
| 4 | 6.63 | 6.13 | 4.89 | 4.81 | 5.55 | 6.85 | 5.45 | NR |
| 5 | 8.59 | 7.89 | 6.34 | 6.88 | 7.63 | 8.94 | 7.34 | NR |
| 6 | 8.58 | 8.45 | 6.06 | 7.03 | 8.13 | 9.58 | 7.36 | NR |
| 7 | 4.31 | 4.29 | 1.33 | 2.19 | 3.95 | 5.38 | 3.1 | NR |
| 8 | 7.56 | 7.38 | 6.44 | 6.45 | 6.98 | 8.19 | 11.95 | NR |
| 9 | 8.24 | 7.98 | 7.95 | 7.19 | 7.9 | 9.07 | 10.9 | NR |
| 10 | 6.42 | 6.67 | 5.82 | 5.68 | 6.4 | 7.7 | 6.7 | NR |
| 11 | 6.11 | 5.69 | 4.73 | 4.78 | 5.69 | 7.46 | 5.2 | NR |
| 12 | 10.7 | 10.24 | 8.61 | 8.77 | 10.15 | 11.75 | 9.42 | NR |
| 13 | 8.71 | 8.72 | 6.59 | 6.94 | 8.3 | 9.8 | 7.8 | NR |
| 14 | 5.58 | 8.47 | 3.44 | 3.98 | 5.05 | 6.2 | 4.8 | NR |
| OW | 6.57 | 6.38 | 4.45 | 5.06 | 4.98 | 7.74 | 5.53 | NR |
| | | | | | | | | |
| * - from top of casing | | | | | | | | |
| NR - Not Reported | | | | | | | | |

**ENVIRONMENTAL RESOURCE PERMITTING**

1. *Section 3.8.9 Storm water Management System*

*This section states that the system has been designed with a permanent pool residence time of 14 days. Since no littoral zone is proposed in the detention pond design a minimum 21-day residence is required per 40C42.26(4) F.A.C. Please provide supporting calculations.*

*This section states that the system has been designed to attenuate the peak discharge from the 100-year, 24-hour storm. Please provide a pre-post demonstration for the 25 year/24 hour and mean annual (2.3) year/24 hour design storms using the SCS II (Florida Modified) Rainfall Distribution. The 25-year storm is the design storm for projects within the SJRWMD and the mean annual storm is required for projects within the Econ Basin. Please provide inputs and output for any routing runs used in the demonstration.*

*a. Please provide state storage calculations with indicated levels and associated volume for permanent pool as well as pollution abatement levels.*

*b. Please provide a recovery demonstration indication of the orifice meets the bleed down requirements in 40C-42.026(4)(b).*

***Response:*** **Response:** The existing permanent pool volume provides residence time in excess of the 21 day requirement outlined in 40C42.26(4) F.A.C. Supplemental calculations are as follows:

**Permanent Pool :**

$$PPV_{rqd} = \frac{DA \times C \times R \times RT}{WS \times CF} = \frac{(52)(0.78)(31)(21)}{(153)(12)} = 14.38 \text{ acre-ft} = 626{,}461 \text{ ft}^3$$

where PPV = Permanent pool volume (acre-ft)

RT = Residence time (days)

R = Wet season rainfall (inches)

FR = Average flow rate (acre-ft/day)

CF = 12 (inches / foot)

C = runoff coefficient

$$C = \frac{(41.2 \text{ acres} \times 0.9) + (10.8 \text{ acres} \times 0.30)}{52 \text{ acres}} = 0.78$$

$PPV_{provided} = 734{,}254 \text{ ft}^3$

$PPV_{provided} > PPV_{rqd}$, therefore the existing permanent pool is adequate.

Pre-Post routing demonstrations, stage-storage calculations, and orifice design are provided in the Storm Water. Management Plan immediately following Section 3.10 of the Supplemental Site Certification Application. Figure-2 has been revised to show a 90' elbow in the 5" pipe through the weir and is attached.

2. *Section 2.3.3 Vegetation*

*This section describes the types of common plants found and animals observed in SEC's entire parcel (excess of 3,000 acres). However, the report does not specifically address the vegetation and animals found with the 60 acre expansion site for Stanton A, or within the proposed Substation, utilizing the Natural Gas Pipeline and for the Transmission line. In addition, the report references a botanical survey conducted from 1980 to 1981. Please provide more recent data for the site.*

**Response:**

**Expansion Site**

The expansion site for Stanton A is on site property that has been prepared (filled) for future facilities, and used as a construction and equipment lay-down area for the original facility. This flat-graded area, which contains various railroad spur tracks and storm water control features, is currently maintained with regular mowing. There is no cover for wildlife species in this area, therefore, it is considered poor wildlife habitat. The mowed vegetation in the expansion area is dominated by dallis grass (*Paspalum* spp.) and witchgrass (*Dichanthelium* spp.).

Use of the 60-acre expansion site by animals is limited by the lack of habitat, the exposure to activities associated with operation and maintenance of SEC, and the 8-foot, chainlink fence that surrounds the site. However, according to a literature search and observed conditions, animals that may occasionally bypass the fence via open gates or pass through, under or over the fence include: **Mammals:** white-tailed deer (*Odocoileus virginianus*), eastern cottontail (*Syvilagus floridanus*), nine-banded armadillo (*Dasypus novemcinctus*), harvest mouse (*Reithrodontomys humulis*), old-field mouse (*Peromyscus polionotus*), Red Fox (*Vullpes vulpes*), striped skunk (*Mephitis mephitis*), raccoon (*Procyon lotor*), Virginia opossum (*Didelphis virginiana*), **Amphibians:** eastern narrow-mouth toad (*Scaphiopus holbrookii*), southern toad (*Bufo terrestris*), **Reptiles:** Florida box turtle (*Terrapene carolina bauri*), brown anole (*Anolis sagrei*), green anole (*Anolis carolinensis*), fence lizard (*Scelopaorus undulatus*), rat snake (*Elaphe obsoleta*), **Birds:** killdeer (*charadrius vociferus*), mourning dove (*Zenaida macroura*), rock dove (*Columba livia*), eastern kingbird (*Tyrannus tyrannus*), American crow (*Corvus brachyrhynchos*), American robin (*Turdus migratorius*), eastern meadowlark (*Sturnella magna*), Boat-tailed grackle (*Quiscalus major*), and common grackle (*Quiscalus quiscula*)

**Substation Expansion Area**

The substation expansion will occur in a 1.2-acre area immediately adjacent to and west of the existing SEC Substation No. 17 (9.2 acres). During site visits (11/7/00-11/9/00 and 12/6/00), the vegetation observed in this area included: longleaf pine (*Pinus palustris*), bushy bluestem (*Andropogon glomeratus*), lovegrass (*Eragrostis* spp.), coinwort (*Centalla asiatica*), dog fennel (*Eupatorium capilfolium*), saw palmetto (*Serenoa repens*), wax myrtle (*Myrica cerafer*), and wiregrass (*Aristida stricta*). The vegetation in this 1.2-acre area provides moderate habitat for wildlife. The proposed substation expansion area is currently not fenced and could potentially support most of the animals listed in Section 2.3.5 at some time. However, due to the proximity of the expansion area to the existing substation some of these animals will likely avoid areas immediately next to the substation because of operation and maintenance activities.

**Transmission Line Corridor**

The transmission line corridor passes through pine flatwoods and cypress wetland vegetative communities. However, the proposed transmission line route follows an existing maintenance trail to avoid and minimize impacts to wetlands and wildlife habitat. Plants observed in these areas during recent site visits (11/7/00-11/9/00 and 12/6/00) and identified in the most recent biological monitoring report for Stanton Energy Center mitigation areas (October 23, 1999) include: broomsedge (*Andropogon vrginicus*), bushy bluestem (*Andropogon glomeratus*), three-awn (*Aristida affinis*), bottlebrush three-awn (*Aristida spiciformis*), wiregrass (*Aristida stricta*), groundsel tree (*Baccharis halimnifolia*), blue hyssop (*Bacopa caroliniana*), partridge-pea (*Cassia chamaecrista*), coinwort (*Centella asiatica*), pineland daisy (*Chaptalia tomentosa*), Leavenworth's tickseed (*Coreopsis leavenworthii*), flatsedge (*Cyperus* spp.), coastal lovegrass (*Eragrostis refracta*), lovegrass (*Eragrostis* sp.), plumegrass (*Erianthus giganteus*), dog fennel (*Eupatorium capillifolium*), bushy goldenrod (*Euthamia minor*), marsh pennywort (*Hydrocotyle umbellata*), four-petal St. John's–wort (*Hypericum tetrapetalum*), St. John's-wort (*Hypericum* sp.), Inkberry (*Ilex glabra*), white-head bogbutton (*Lachnocaulon anceps*), redroot (*Lacnanthes caroliniana*), fetterbush (*Lyonia lucida*), wax myrtle (*Myrica cerifera*), longleaf pine (*Pinus palustris*), beakrush (*Rhynchospora* spp.), nutgrass (*Scleria baldwiniana*), nutgrass (*Scleria reticularis*), saw palmetto (*Serenoa repens*), bald cypress (*Taxodium distichum*), yellow-eyed grass (*Xyris caroliniana*), yellow-eyed grass (*Xyris* sp.).

The transmission line corridor and vicinity currently provides moderate wildlife habitat and may potentially support the following animals: **Mammals:** Virginia opossum (*Didelphis virginiana*), southeastern shrew (*Sorex longirostris*), southern short-tailed shrew (*Blarina carolinensis*), least shrew (*Cryptotis parva*), eastern pipistrelle (*Pipistrellus subflavus*), big brown bat (*Eptesicus fuscus*), hoary bat (*Lasiurus cinereus*), northern yellow bat (*Lasiurus intermedius*), seminole bat (*Lasiurus seminolus*), evening bat (*Nycticeius humeralis*), Rafinesque's big-eared bat (*Corynorhinus rafinesquii*), brazilian free-tailed bat (*Tadarida brasiliensis*), nine-banded armadillo (*Dasypus novemcinctus*), eastern cottontail (*Sylvilagus floridanus*), marsh rabbit (*Sylvilagus palustris*), marsh rice rat (*Oryzomys palustris*), harvest mouse (*Reithrodontomys humulis*), cotton mouse (*Peromyscus gossypinus*), golden mouse (*Ochrotomys nuttalli*), hispid cotton rat (*Sigmodon hispidus*), round-tailed muskrat (*Neofiber alleni*), coyote (*Canis latrans*), Red Fox (*Vulpes vulpes*), gray fox (*Urocyon cinereoargenteus*), raccoon (*Procyon lotor*), long-tailed weasel (*Mustela frenata*), striped skunk (*Mephitis mephitis*), bobcat (*Lynx rufus*), feral pig (*Sus scrofa*), white-tailed deer (*Odocoileus virginianus*), **Amphibians:** eastern narrow-mouth toad (*Scaphiopus holbrooki*), crawfish frog (*Rana areolata*), pig frog (*Rana grylio*), southern leopard frog (*Rana utricularia*), eastern narrow-mouth toad (*Gastrophryne carolinensis*), oak toad (*Bufo querecius*), southern toad (*Bufo terrestris*), Florida cricket frog (*Hyla cinerea cinerea*), Pine woods treefrog (*Hyla femoralis*), barking treefrog (*Hyla gratiosa*), squirrel treefrog (*Hyla squirella*), chorus frog (*Pseudacris nigrita*), little grass frog (*Limnaoedus ocularis*), **Reptiles:** Florida box turtle (*Terrapene carolina bauri*), brown snake (*Storeria dekayi*), mud snake (*Farancia abacura*), pine snake (*Pituouphis melanoleucus*), Florida cottonmouth (*Agkistrodon piscivorus conanti*), rat snake (*Elaphe obsoleta*), **Birds:** cattle egret (*Bubulcus ibis*), turkey vulture (*Cathartes aura*), black vulture (*Coragyps atratus*), red-tailed hawk (*Buteo lineatus*), marsh hawk (*Circus cyaneus*); American kestrel (*Falco sparverius*), bobwhite (*Colinus virginianus*), killdeer (*Charadrius vociferus*), mourning dove (*Zenaida macroura*), eastern kingbird (*Tyrannus tyrannus*), great crested flycatcher (*Myiarchus crinitus*), American crow (*Corvus brachyrhynchos*), American robin (*Turdus migratorius*), Carolina chickadee (*Parus carolinensis*), house wren (*Troglodytes aedon*), mockingbird (*Mimus plyglottos*), eastern bluebird (*Sialia sialis*), loggerhead shrike (*Lanius ludovicianus*), yellow-rumped warbler (*Dendroica coronata*), pine warbler (*Dendroica pinus*), eastern meadowlark (*Sturnella magna*), Boat-tailed grackle (*Quiscalus major*), common grackle (*Quiscalus quiscula*), northern cardinal (*Cardinalis cardinalis*), and savannah sparrow (*Passerculus sandvicensis*).

**Natural Gas Pipeline Corridor**

The natural gas pipeline route is located entirely within the OUC utility corridor extending south from the main SEC property, and more specifically, adjacent to the maintenance trail within the corridor. The vegetation in these areas is mostly maintained as lawn for maintenance and operation of the transmission line and railroad tracks. Common plants observed in these areas during recent site visits (11/7/00-11/9/00 and 12/6/00) and identified in the most recent biological monitoring report for Stanton Energy Center mitigation areas (October 23, 1999) include: bahiagrass (*Paspalum notatum*), bushy bluestem (*Andropogon glomeratus*), little bluestem (*Schizachrium scoparium*), witch grasses (*Dichanthelium* spp.), groundsel tree (*Baccharis halimnifolia*), dog fennel (*Eupatorium capillifolium*), and bushy goldenrod (*Euthamia minor*). Common animals occurring in this area are similar to those found in the SEC Stanton A expansion area.

3. *Section 3.3.3.2 mentions that the existing rail line will be upgraded northwest of the coal units. What does the upgrade entail to the rail line? Addition impacts to wetlands, additional impervious storm water concerns, etc?*

   **Response:** Potential upgrades include new ballast, track/tie replacement, reconnections. No additional impacts to wetlands or additional impervious storm water concerns are anticipated.

4. *Please provide the Central District with a copy of the Orlando Utilities Commission Joint Agency Mitigation Monitoring Plan (1992).*

   **Response:** A copy of the Joint Agency Mitigation Monitoring Plan is included as Attachment D.

5. *Section 4.1.1 identifies general construction impacts. The 60 acre Stanton A is described as "generally maintained grassland." This is not sufficient information/description to conclude that the area is an upland. Please clarify and revise accordingly.*

   a. *Please provide a copy of the wetland determination for this parcel.*

   b. *Was a formal binding determination permitted by the Department? If yes, please provide a copy.*

   c. *Specifically identify all wetland areas proposed for impact (including temporary and permanent and for the conversion of a forested system to herbaceous wetland).*

   **Response:** The 60 acre Stanton A expansion area was graded, filled, and prepared during construction for Units 1 and 2. The area was used for equipment laydown during construction of Units 1 and 2 and included within the previously certified area for potential future development. The vegetation is dominated by dallisgrass (*Paspalum dilatatum*) and Bermuda grass (*Cynodon dactylon*), which is currently maintained with regular mowing. When the expansion area was prepared, a storm water management system was also constructed. These storm water structures include drainage swales, culverts, and a detention pond. The detention pond will be regraded to meet detention requirements associated with Stanton A. The altered vegetation, hydrology, and soils of this parcel do not exhibit wetland attributes.

   a. No wetland determination was prepared for this parcel. Grading and storm water activities and environmental impacts associated with the expansion area were included in the Site Certification for Units 1 and 2.

   b. No evidence of a formal binding determination was found.

   c. **Substation Expansion Area (W1 on Figure 6.1-1 in SSCA)**

The wetland impact area within the substation expansion area is identified as W1 and is a herbaceous wetland. This wetland will be filled with crushed rock and converted to upland. This impact will be permanent and encompass an area of 0.13 acre.

**Transmission Line Corridor (W2, W3, W4, and W6 on Figure 6.1-1 in SSCA)**

Impact area W2 is a herbaceous wetland area within the proposed transmission line corridor. This wetland area will be filled with native soil and converted to upland. This impact will be permanent and will encompass an area of 0.23 acre. This impact area is a proposed site for one of the transmission structures and supporting keyhole pad.

Impact area W3 is a cypress strand area within the proposed transmission line corridor. The trees within the 125-foot wide transmission corridor will be cleared and permanently maintained as an emergent wetland. The impact area is 0.40 acre.

Impact area W4 is a herbaceous wetland within the proposed transmission line corridor. This wetland area will be filled with native soil and converted to upland. This impact will be permanent and will encompass an area of 0.11 acre. This impact area is a proposed site for one of the transmission structures and supporting keyhole pad.

Impact area W6 is a borrow ditch from which soil was removed and used to construct the existing field access road. This surface water will be filled with native soil and converted to upland. This impact will be permanent and will encompass an area of 0.23 acre. This impact includes proposed sites for two transmission structures and supporting keyhole pads.

**Natural Gas Pipeline Corridor (W5 on Drawing 98362-ERP-4A in Section 10.4.4 in the SSCA)**

Impact area W5 is a herbaceous wetland within the proposed gas pipeline corridor. This wetland was mistakenly labeled "forested mixed wetlands" wetland type in Table 6.2-2 of the SSCA. This wetland area was cleared for utility corridor use (railroad, maintenance road, transmission line) and is maintained in a herbaceous state. The existing vegetation is dominated by (*Juncus effusus*), arrowhead (*Sagittaria* sp.), and cattails (*Typha latifolia*). Only a few saplings of red maple (*Acer rubrum*), sweet gum (*Liquidambar styraciflua*), and bald cypress (*Taxodium distichum*) remain in this area. This wetland area will be trenched, the pipeline will be installed, and then the soils will be replaced to original grade. This impact will be temporary and will encompass an area of 0.06 acre. This impact is temporary because the herbaceous vegetation and wetland conditions will be allowed to return.

6. *Drawing Figure 6.1-1 is not legible.*

**Response:** Large scale drawings of the proposed and alternate transmission line routes are attached as Figure 6.1-1. The drawings have been signed and sealed.

7. *Please provide clear detailed plan and cross section drawings to the proposed transmission line. Specifically include:*

   *a. road names*
   *b. location of existing line (with dimensions)*
   *c. location of proposed line (with dimensions)*
   *d. location of wetlands, ditches, surface waters, etc. (in numerical order)*
   *e. length and width of the line that will impact wetlands*
   *f. legend for wetlands including type and acreage*
   *g. cross section location*
   *h. location of the proposed road*
   *i. substation location and dimensions*
   *j. concrete pad locations with dimensions*
   *k. turbidity barrier type and location*
   *l. other pertinent information*

**Response:**

a) There are no named roads in the near vicinity of the transmission line, which is entirely on SEC property. The closest road is Alafaya Trail. This road is now marked on Drawing TLINE3, Figure 6.1-1, revised on March 21, 2001.
b) The existing transmission lines going south out of the SEC Substation are now shown on Drawing TLINE 3, Figure 6.1-1.
c) The location of the transmission centerline is shown on Figure 6.1-1.
d) Revised Drawing TLINE3, Figure 6.1-1 illustrates the location of the wetlands, ditches, surface waters in numerical order (W-1 through W-6).
e) Revised Drawing TLINE3, Figure 6.1-1 illustrates the size and width of the transmission line impacts.
f) A legend providing wetland type and acreage can be found on Drawing 98362-ERP-4.
g) The cross section location is shown on Figure 6.1-1.
h) The applicants are not proposing to construct any roads for the proposed transmission line route.
i) The Substation location and impact area are shown on Figure 6.1-1.
j) There will be no large concrete pads. Structures will be either concrete or steel poles. Concrete poles will be directly embedded. Steel poles will either be direct embedded or supported by concrete pier foundations.

k) Turbidity barriers are shown on Drawing 98362 ERP-1A in Section 10.4 of the SSCA.
l) There is no other pertinent information.

8. *Revise the cross section drawings to provide:*

*a. width of the line/corridor*
*b. cross hatch fill in wetlands, surface waters, ditches, etc.*
*c. legend to the cross hatched areas*
*d. acreage to the impact areas*
*e. all dimensions to toe of slope*
*f. dimension to slope to the keypad.*

**Response:**

a) The width and length of line is shown on Figure 6.1-1.
b) TLINE3, Figure 6.1-1 provides a plan view of the transmission line and includes cross hatched wetlands, surface waters, ditches. Figure 6.1-1 also includes a cross section of the transmission line indicating the impact area within the adjacent borrow ditch.
c) Figure 6.1-1 provides a legend to cross hatched areas.
d) Figure 6.1-1 provides acreages to the impact areas.
e) The toe of slope has a 3:1 ratio using a unitless measure.
f) The distance between the transmission pole and the toe of slope of the keyhole pad is 56' with 2' of fill or 59' with 3' of fill.

9. *Demonstrate why a new 125 feet wide corridor is necessary for the proposed transmission line. Please provide avoidance/minimization and alternatives considered for the new line.*

**Response:** Under high wind conditions such as those generated by hurricane winds, the transmission structures deflect and the conductors (wires) blow out (swing) significantly. The right-of-way width selected is the minimum width to keep the conductors contained on the right-of-way under these conditions, as required by electric codes. In addition, Florida has established limits for electric and magnetic fields within and at the edge of rights-of-way. Again the right-of-way width selected is the minimum width to satisfy the Florida Statute regarding EMF.

The proposed route was selected over the alternate route due to environmental impacts, cost, and the need to construct access roads. Although the alternate route would have paralleled the existing transmission lines, this route had additional wetlands impacts from construction of both access roads and key hole pads.

10. *Section 6.1.8.1.*

a. *Are culverts required to maintain hydrologic flow? If yes, please reflect on the plan and cross section drawings.*

b. *Where are the concrete foundations being installed? (Identify on the drawings any that will be in wetlands, ditches, surface waters, etc. and provide dimensions).*

**Response:**

a. No access roads or flow constraints are being constructed for the transmission line. As such, no culverts are being installed. Storm water will flow naturally around the key hole pads.

b. The concrete pier foundations for the transmission line structures will be located directly under the transmission structures. The locations and dimensions of these structures are shown on revised Figures 6.1-1 and 6.1-2, which are attached.

11. *Section 6.1.8.4*

*Identifies 0.4 acres of forested cypress strand to be cleared. Table 6.1-3 indicates clearing will be permanent. Please identify whether the entire area will be converted from a forested wetland to herbaceous wetland or from a forested wetland to upland filled area. Please revise the drawing and tables/exhibits accordingly.*

**Response:** The forested cypress strand (0.4 acre) referenced in Table 6.1-3 will be converted to and maintained as herbaceous wetland; no fill is required or proposed to this area. A revised Figure 98362-ERP-4 identifies the wetland impact types (*i.e.*, fill or clear) for the permanent wetland impact areas.

12. *6.2 Natural Gas Pipeline*

*Where is the 4.5 mile 16 inch FGT transmission line located?*

a. *Demonstrate why a 16-inch pipeline requires a 50 feet wide permanent corridor.*

b. *Drawing Figure 6.2-1 may serve as an overall location map for the proposed natural gas pipeline provided road names and section, townships and ranges were added to the drawing and the drawing is legible.*

c. *Detailed plan and cross section drawing are required for the entire pipeline. Include in the plan view drawing:*
   - *a) wetland locations*
   - *b) wetland types*

*c) cross hatch proposed wetland impacts*
*d) location of the proposed pipeline*
*e) temporary work area with dimension*
*f) cross hatch wetland impacts*
*g) legend to the proposed wetland impacts*
*h) dimensions (length and width) to the impacts*
*i) road names*
*j) north arrow*
*k) cross section*

**Response:**

6.2 Natural Gas Pipeline

The 26" FGT supply line is located approximately 1.5 miles south of the Bee-Line, as shown on Figure 2.1-1 in the SSCA.

a. Except where the gas pipeline crosses Bee Line Expressway right-of-way, the entire route is on OUC property. The 35-foot corridor is entirely within the larger OUC corridor (which was disturbed with the installation of the railroad and southern access road) and is required for pipeline access and maintenance. The 35-foot area would support trucks, repair equipment, temporary spoil area, and pipe laydown area.

b. Revised Figure 6.2-1 is included herein and provides the requested legal description for the location of the project and the natural gas pipeline. Refer to Drawing 098362-DS-S3300 for road names and locations.

c.
   a) See Drawings S3306, Rev. 1 and S3308, Rev. 1, which are included in Attachment E.
   b) See Drawings S3306, Rev. 1 and S3308, Rev. 1 in Attachment E.
   c) See Drawings S3306, Rev. 1 and S3308, Rev. 1 in Attachment E.
   d) See Drawings S3300-S3309 in Attachment E as well as Figure 6.2-1, Figure 6.2-2 (revised, dated 04-17-2001), and Figure 6.2-2A (new, dated 04-17-2001).
   e) The temporary work area is the area within the silt fencing as shown on Drawings S3300-S3309 in Attachment E.
   f) See the response in 12(c).
   g) See Drawing 98362-ERP-4A.
   h) See Drawing 98362-ERP-4A.
   i) See Drawing S3300, Rev. 1, in Attachment E.
   j) North arrows are on all drawings that require one.
   k) See Figures 6.2-2 and 6.2-2A.

*13. Cross section drawings are necessary for the wetland, surface water and ditch crossings. Include the following:*

*a. identify cross section*

*b.* *width of cross section*

*c.* *cross hatch impacts*

*d.* *location of the existing railway, unimproved roadway, etc.*

*e.* *location of the transmission line*

*f.* *culvert type, size, dimensions, invert*

*g.* *stabilization type*

*h.* *turbidity type and location*

**Response:** Figure 6.2-2A has been created to show these details. Drawings S3300-S3309 in Attachment E provide location information and silt fence installations. No culverts are required.

14. *Please indicate avoidance/minimization considerations for the transmission line installation. Include documentation regarding the construction of this line by directional bore.*

**Response:** The applicants believe the question was meant to refer to the natural gas pipeline and have addressed the pipeline considerations in this response. No alternatives to the proposed gas pipeline route were considered between the FGT pipeline and Stanton A. During the selection of potential routing options, the primary objectives were to minimize impacts to wetlands, wildlife, protected species, such as the red-cockaded woodpeckers, and to follow existing linear facilities in the project area. The proposed route was the obvious choice. It is the shortest possible route and will have a minimal impact on the environment. The choice to place the gas pipeline adjacent to existing roadways and within existing utility corridors appears to be a logical routing option.

Regarding the construction of this line by directional bore, trenching was chosen over directional boring based on the high cost of directional boring and the minimal impact to the small, poor quality wetland to be crossed.

15. *Provide a copy of the permit file number, type of permit, date authorized for the existing 26 inch FGT gas line.*

**Response:** The FGT 26 inch mainline was authorized pursuant to FERC Docket No. CP65-393.

16. *Will the pipeline cross any surface waters? If yes, please identify all surface waters in your drawings. Please note that if the surface waters are determined to be sovereign submerged lands than a public easement will be necessary for all sovereign impacts.*

**Response:** The proposed pipeline will cross two surface waters. Following the pipeline route from the north to south, the first surface water is located on SEC property (Drawing S3306, rev. 1). At this point, the pipeline will be attached to the existing access road bridge for an aerial crossing. The second surface water crossing is illustrated on Drawing S3308, rev. 1, included in Attachment E. The gas pipeline will be installed within the existing dirt access trail for the second surface water crossing. Drawings S3306, rev. 1 and S3308, rev. 1 illustrating surface water locations are enclosed in Attachment E in response to sufficiency questions 12 and 22.

These areas do not include sovereign submerged lands, as indicated by letter dated March 13, 2001, from FDEP's Bureau of Public Land Administration and attached herein.

17. *Section 6.3.7.2 states that the Green Branch and Turkey Creek will be crossed by the 16-inch natural gas transmission line. Has a title determination been conducted for these locations? Please note as indicated above that if these areas are sovereign submerged lands then a public easement with detailed survey drawings will be required for the impacts crossing any that is sovereign.*

**Response:** These areas do not include sovereign submerged lands, as indicated by letter dated March 13, 2001, from FDEP's Bureau of Public Land Administration and attached herein.

18. *Table 6.2.2 states fill in forested wetlands as a temporary impact. Please clarify. (Typically, the owner of the transmission line does not desire forested systems to recruit within their pipeline and corridor.)*

*Therefore, it appears that the fill in the forested system is permanent impact. Please clarify and revise all documentation.*

**Response:** The wetlands identified in Table 6.2.2 were initially surveyed by review of US Geological Survey maps and National Wetlands Inventory maps. Field surveys were conducted in November and December of 2000. Table 6.2.2 does not reflect field reconnaissance information. Field surveys indicated that the forested mixed wetlands and cypress strands were mistakenly labeled. While these wetlands were forested prior to development of the utility corridor, the impact areas are no longer forested and are maintained in herbaceous or emergent vegetation. The new gas pipeline will not require clearing of forested wetlands, only trenching through emergent wetlands in one area. The trenching impacts will be temporary and herbaceous wetland conditions will be maintained. The revised wetland impacts are given below.

| Table 6.2-2<br>Wetland Areas and Impacts Within the SEC Natural Gas Pipeline Corridor | | |
|---|---|---|
| **Wetland Type** | **$ft^2$/acres** | **Impact Type** |
| Emergent wetland (Forested mixed wetlands) | 2,760/0.06 | Trench/Backfill - Temporary |
| Upland (Cypress strand) | 8,110/0.17 | No Impact - Previously converted |
| Emergent wetland (Cypress strand) | 8,750/0.20 | No Impact - Pipeline will be attached to access road bridge |

*19. Section 6.2.7.3.1 references a survey conducted in 1981. These are outdated.*

**Response:**

**Natural Gas Pipeline Corridor**

The natural gas pipeline route is located immediately next to the SEC access road and within the OUC utility corridor south of the SEC property. The vegetation in these areas is mostly maintained as lawn for maintenance and operation of the transmission line and railroad tracks. Common plants observed in the gas pipeline corridor during recent site visits (11/7/00-11/9/00 and 12/6/00) and identified in the most recent biological monitoring report for Stanton Energy Center mitigation areas (October 23, 1999) include bahiagrass (*Paspalum notatum*), bushy bluestem (*Andropogon glomeratus*), little bluestem (*Schizachrium scoparium*), witch grasses (*Dichanthelium* spp.), groundsel tree (*Baccharis halmnifolia*), dog fennel (*Eupatorium capillifolium*), and bushy goldenrod (*Euthamia minor*). Common animals occurring in the pipeline corridor include: **Mammals:** white-tailed deer (*Odocoileus virginianus*), eastern cottontail (*Syvilagus floridanus*), nine-banded armadillo (*Dasypus novemcinctus*), harvest mouse (*Reithrodontomys humulis*), old-field mouse (*Peromyscus polionotus*), Red Fox (*Vullpes vulpes*), striped skunk (*Mephitis mephitis*), raccoon (*Procyon lotor*), Virginia opossum (*Didelphis virginiana*), **Amphibians:** eastern narrow-mouth toad (*Scaphiopus holbrookii*), southern toad (*Bufo terrestris*), **Reptiles:** Florida box turtle (*Terrapene carolina bauri*), brown anole (*Anolis sagrei*), green anole (*Anolis carolinensis*), fence lizard (*Scelopaorus undulatus*), rat snake (*Elaphe obsoleta*), **Birds:** killdeer (*charadrius vociferus*), mourning dove (*Zenaida macroura*), rock dove (*Columba livia*), eastern kingbird (*Tyrannus tyrannus*), American crow (*Corvus brachyrhynchos*), American robin (*Turdus migratorius*), eastern meadowlark (*Sturnella magna*), Boat-tailed grackle (*Quiscalus major*), and common grackle (*Quiscalus quiscula*).

20. *Section 6.2.8.4 states that the pipeline will have minimal impact on vegetation and is temporary in nature. Please refer to statement regarding permanent impacts above.*

**Response:** Please refer to the response given for Question 18.

21. *Figure 6.2-2 please revise to include the following to this exhibit:*

    a. *total width in wetlands*
    b. *statement that all disturbed area will be returned to pre-existing elevations.*

**Response:** See updated Figures 6.2-2 and 6.2-2A.

22. *No detail plan view drawings were provided for the proposed pipeline.*

    a. *Please note that it appears that mitigation will be required for the conversion of forested wetlands to a herbaceous wetland and for all permanent impacts.*
    b. *What considerations were made for the Substation expansion which in the application reflects 0.13 acres of fill? Please demonstrate avoidance/minimization.*

    **Response:** See Drawings S3300-S3309 in Attachment E.

    a. Due to the minimal wetlands impacts resulting from the development of Unit A, the applicants propose to purchase mitigation banking credits as compensation.

    b. The substation expansion is an unavoidable impact. The new bay for the Unit A connection was placed on the west side of the substation to leave the existing bays for future units open and available using the existing transmission line corridor.

23. *Please note that the drawings provided in the Joint Application for an Environmental Resource Permit application are not legible. (Refer to the questions/statements regarding the plan and cross section drawings above.)*

**Response:** Refer to revised Figure 2, Figure 8, and Drawings 98362-ERP-4, 98362-TLINE2, and 98362-TLINE3.

24. *ERP Drawing 98-362-ERP-4A reflects 2,760 square feet of wetland impacts to Wetland 5 (W5). Please explain why W5 impact (east of the existing roadway) is necessary.*

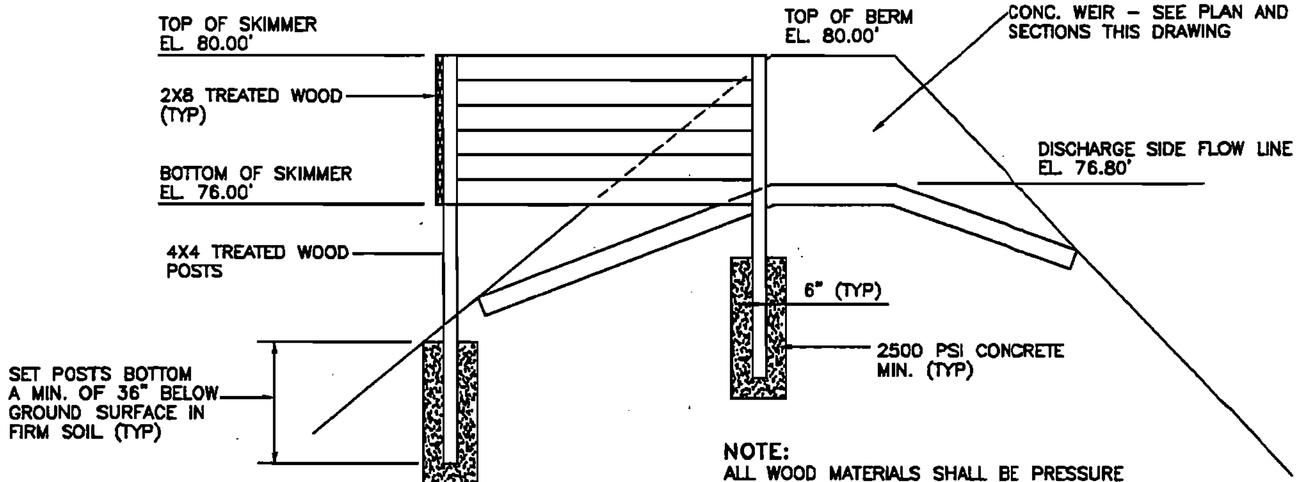
**Response:** Wetland impact area W5 would be a temporary impact to a previously disturbed, low quality herbaceous wetland and is required to install the natural gas pipeline. The wetland area spans the width of the corridor and cannot be reasonably avoided. Alternative installation techniques (i.e. directional bore) would not be cost effective for this small area. The temporary trench would be backfilled with the original excavated material, returned to original contours, and allowed to revegetate to an herbaceous or emergent cover.

25. *The section, Township and Ranges in the maps/drawings are not legible.*

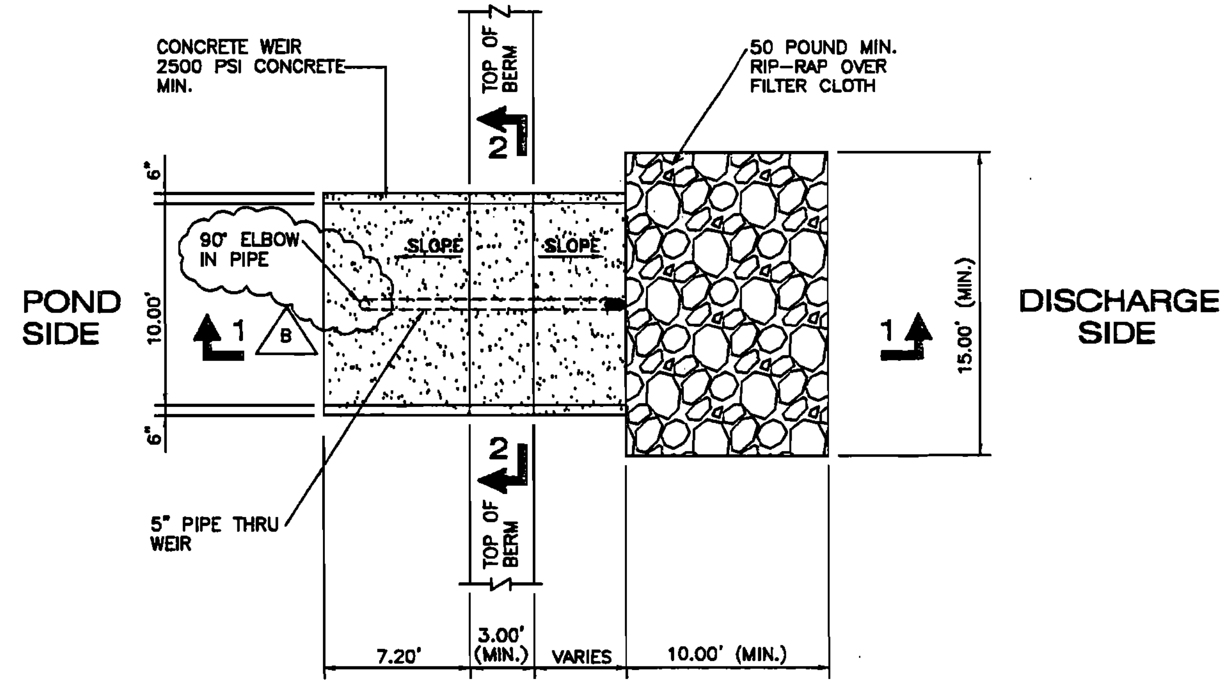
**Response:** A revised Figure 2, Property Location, is included herein and provides the requested Sections, Townships and Ranges for the project.

Storm Water Pond Section and Details
Figure 2, Rev. B

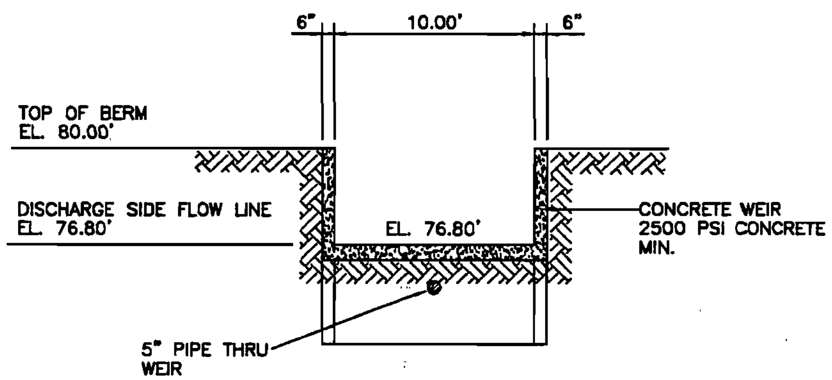
FIGURE-2



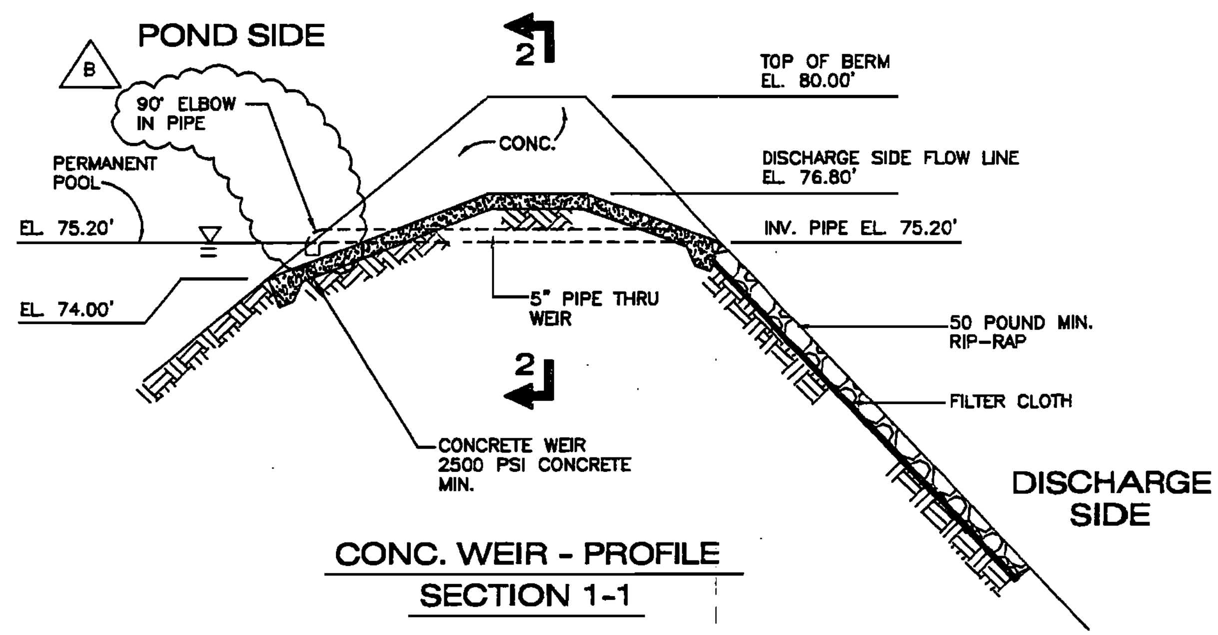

SECTION THRU OIL SKIMMER



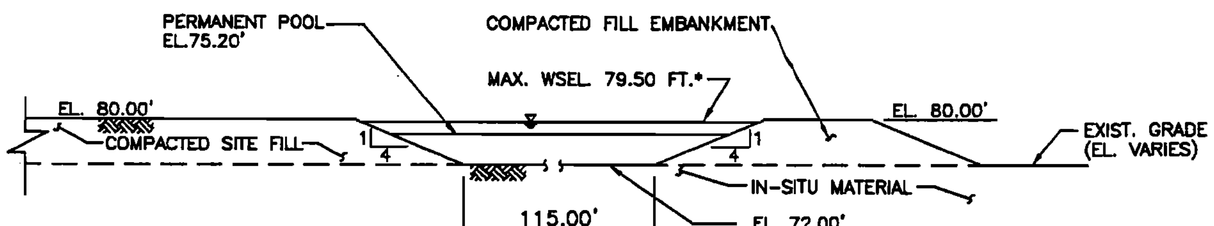

PLAN VIEW AT CONCRETE WEIR




CONC. WEIR
SECTION 2-2




CONC. WEIR - PROFILE
SECTION 1-1




*RESULTING FROM RUNOFF AND DIRECT PRECIPITATION FROM 100-YEAR, ANNUAL RAINFALL

SECTION 3-3
LOOKING WEST
SECTION TAKEN ON FIGURE-1

CAD FIGURE-2.DWG
AutoCad CMF-20001



Southern Company Services, Inc.
FOR
SOUTHERN COMPANY GENERATION

STANTON ENERGY CENTER - UNIT A
1-2x1 COMBINED CYCLE BLOCK
SECTIONS AND DETAILS

| REVISION | DATE | DESCRIPTION | BY | CHK'D |
|---|---|---|---|---|
| B | 4/04/01 | ADDED 90° ELBOW IN 5" PIPE THRU WEIR | CMF | RCB |
| A | 01/12/01 | ISSUED FOR REVIEW | CMF | |

| DESIGNED | DRAWN | CHECKED | SCALE | PROJECT I.D. | DRAWING NUMBER | REV. |
|---|---|---|---|---|---|---|
| RCB | CMF | | NONE | | FIGURE-2 | B |

Figure 6.1-1:
TLINE2
TLINE3


| NO | DATE | REVISIONS AND RECORD OF ISSUE | BY | CHK | APP | FLM |
|---|---|---|---|---|---|---|
| 0 | | INITIAL ISSUE | | | | |

| DRAWING STATUS – PROJECT: | DATE | APPROVED |
|---|---|---|
| NOT TO BE USED FOR CONSTRUCTION | | |
| RELEASED FOR EQUIPMENT/STRUCTURE FABRICATION | | |
| RELEASED FOR CONSTRUCTION | | |
| CONFORMED TO CONSTRUCTION RECORDS | | |

BLACK & VEATCH

ENGINEER MSS | DRAWN TRA | CHECKED | DATE

# ORLANDO UTILITIES COMMISSION
ORLANDO, FLORIDA

STANTON ENERGY CENTER COMBINED CYCLE PROJECT
T-LINE SILT FENCE PLAN

PROJECT 98362 | CAD NO. TLINE2 | DRAWING NUMBER TLINE2

FIGURE 6.1-1

PTBORD 1-17-01 1=1

3/27/01


| NO | DATE | REVISIONS AND RECORD OF ISSUE | BY | CHK | APP | FLM |
|---|---|---|---|---|---|---|
| 0 | | INITIAL ISSUE | | | | |

DRAWING STATUS – PROJECT:

| | DATE | APPROVED |
|---|---|---|
| NOT TO BE USED FOR CONSTRUCTION | | |
| RELEASED FOR EQUIPMENT/STRUCTURE FABRICATION | | |
| RELEASED FOR CONSTRUCTION | | |
| CONFORMED TO CONSTRUCTION RECORDS | | |

BLACK & VEATCH

ENGINEER MSS DRAWN TRA
CHECKED DATE

ORLANDO UTILITIES COMMISSION
ORLANDO, FLORIDA

STANTON ENERGY CENTER COMBINED CYCLE PROJECT
T-LINE SILT FENCE PLAN

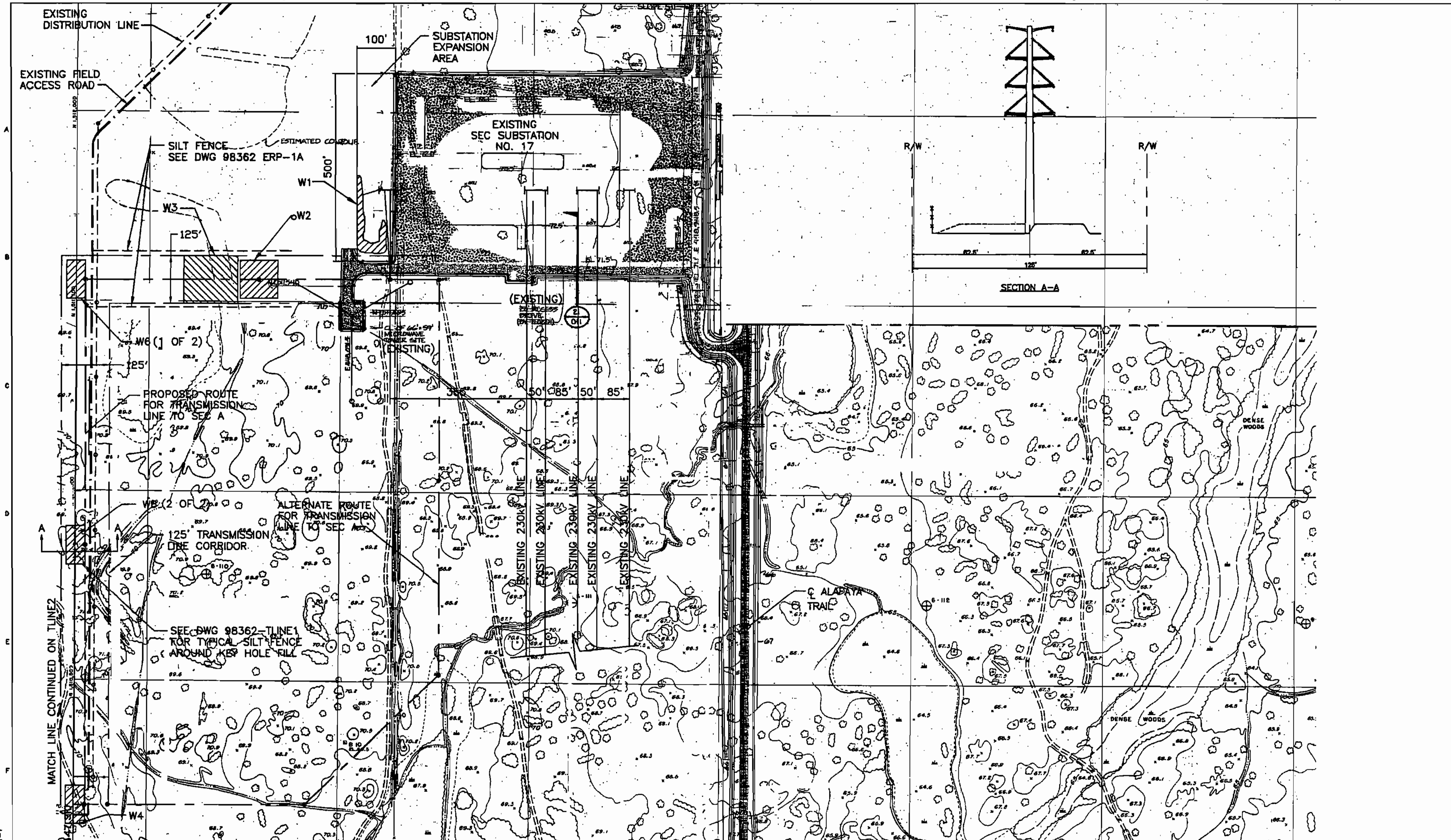
PROJECT 98362
CAD NO. TLINE3
DRAWING NUMBER TLINE3
FIGURE 6.1-1

PTBORD 1-17-01

1=1

3/27/01

Wetland Impact Areas
Drawing 98362-ERP-4




# LEGEND

FILL IMPACTS

CLEARING IMPACTS

| IMPACT AREA | DESCRIPTION |
|---|---|
| W1 | HERBACEOUS WETLAND (0.13 ACRE) |
| W2 | HERBACEOUS WETLAND (0.23 ACRE) |
| W3 | CYPRESS WETLAND (0.40 ACRE) |
| W4 | HERBACEOUS WETLAND (0.11 ACRE) |
| *W5 | HERBACEOUS WETLAND (0.06 ACRE) |
| W6 | SURFACE WATER (TOTAL = 0.23 ACRE) |

* IMPACT AREA W5 IS SHOWN ON DRAWING 98362-ERP-4A.

STANTON ENERGY CENTER
COMBINED CYCLE PROJECT

WETLAND IMPACT AREAS

DRAWING 98362-ERP-4

| NO | DATE | REVISIONS AND RECORD OF ISSUE | BY | CHK | APP | FLM |
|---|---|---|---|---|---|---|
| 0 | | INITIAL ISSUE | | | | |

DRAWING STATUS – PROJECT:
NOT TO BE USED FOR CONSTRUCTION
RELEASED FOR EQUIPMENT/STRUCTURE FABRICATION
RELEASED FOR CONSTRUCTION
CONFORMED TO CONSTRUCTION RECORDS

BLACK & VEATCH

ORLANDO UTILITIES COMMISSION
ORLANDO, FLORIDA

STANTON ENERGY CENTER COMBINED CYCLE PROJECT
T-LINE SILT FENCE PLAN

PROJECT 98362
DRAWING NUMBER TLINE3
CAD NO. TLINE3

ENGINEER MSS DRAWN TRA

ACAD 14_01
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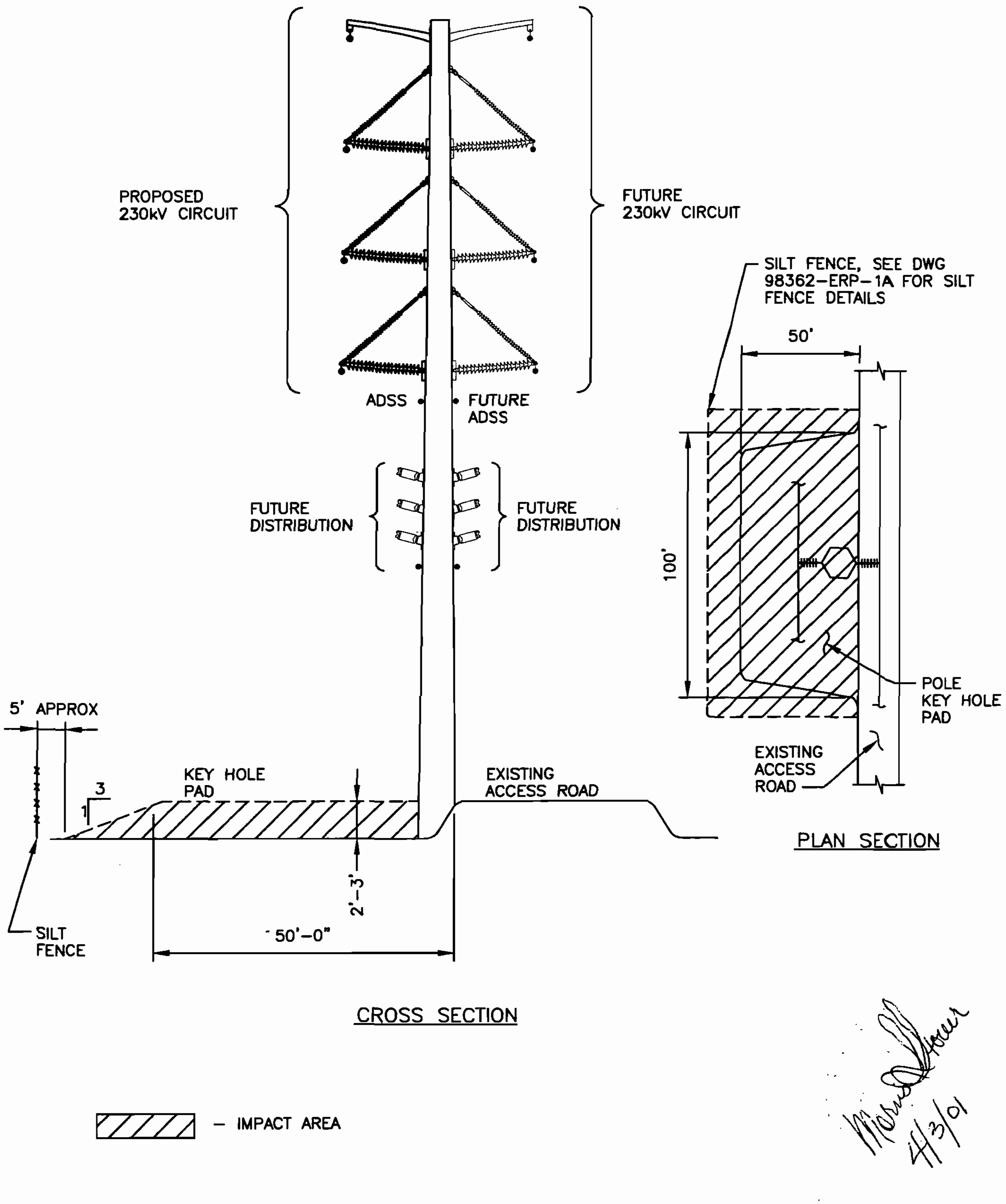
1-17-01

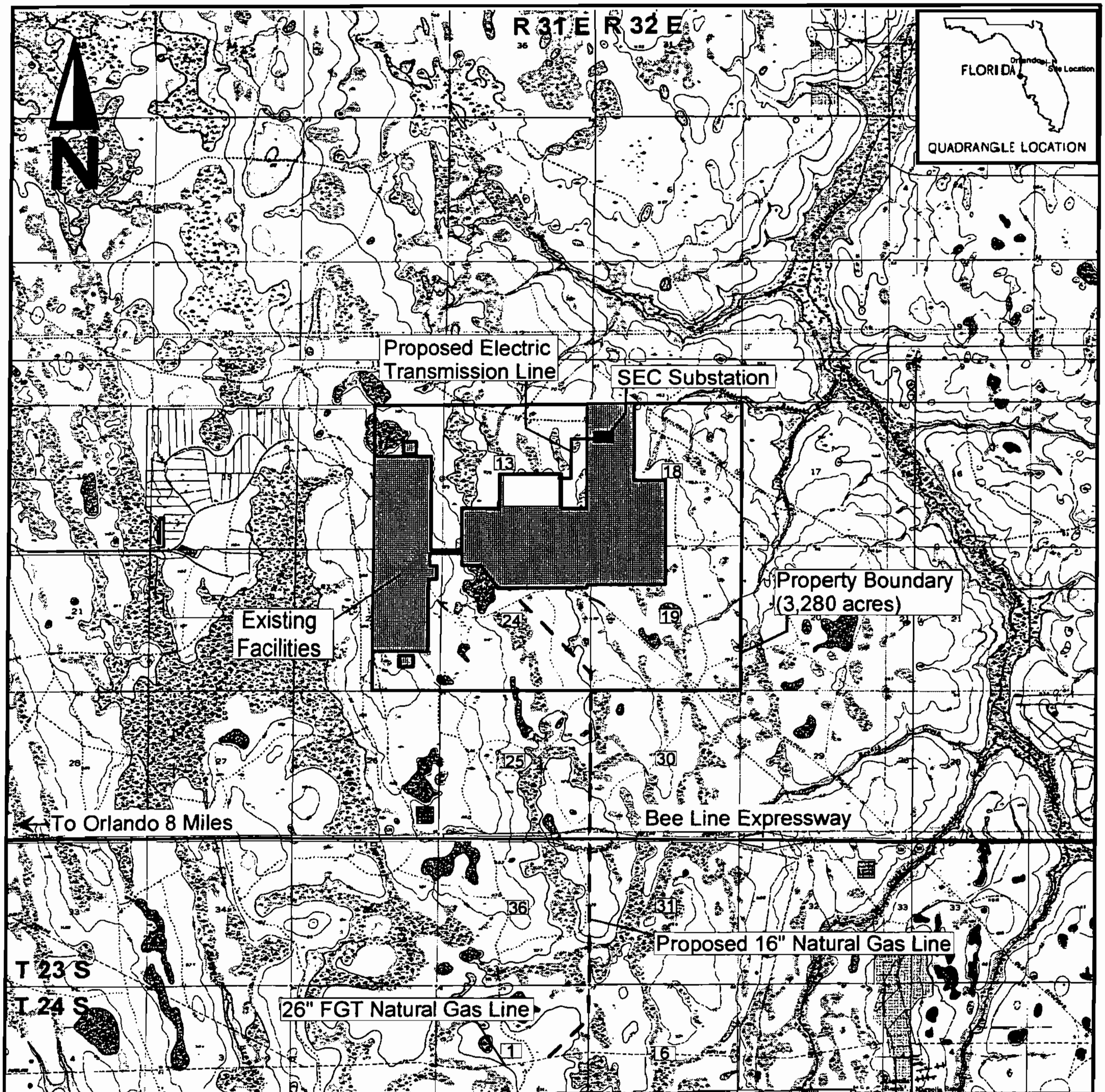
Typical Transmission Tower Structures
Figure 6.1-2



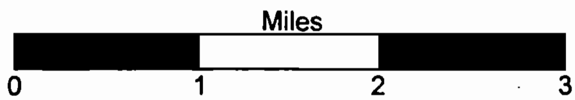

TYPICAL TRANSMISSION TOWER STRUCTURES

FIGURE 6.1–2

Location Map
Figure 6.2-1



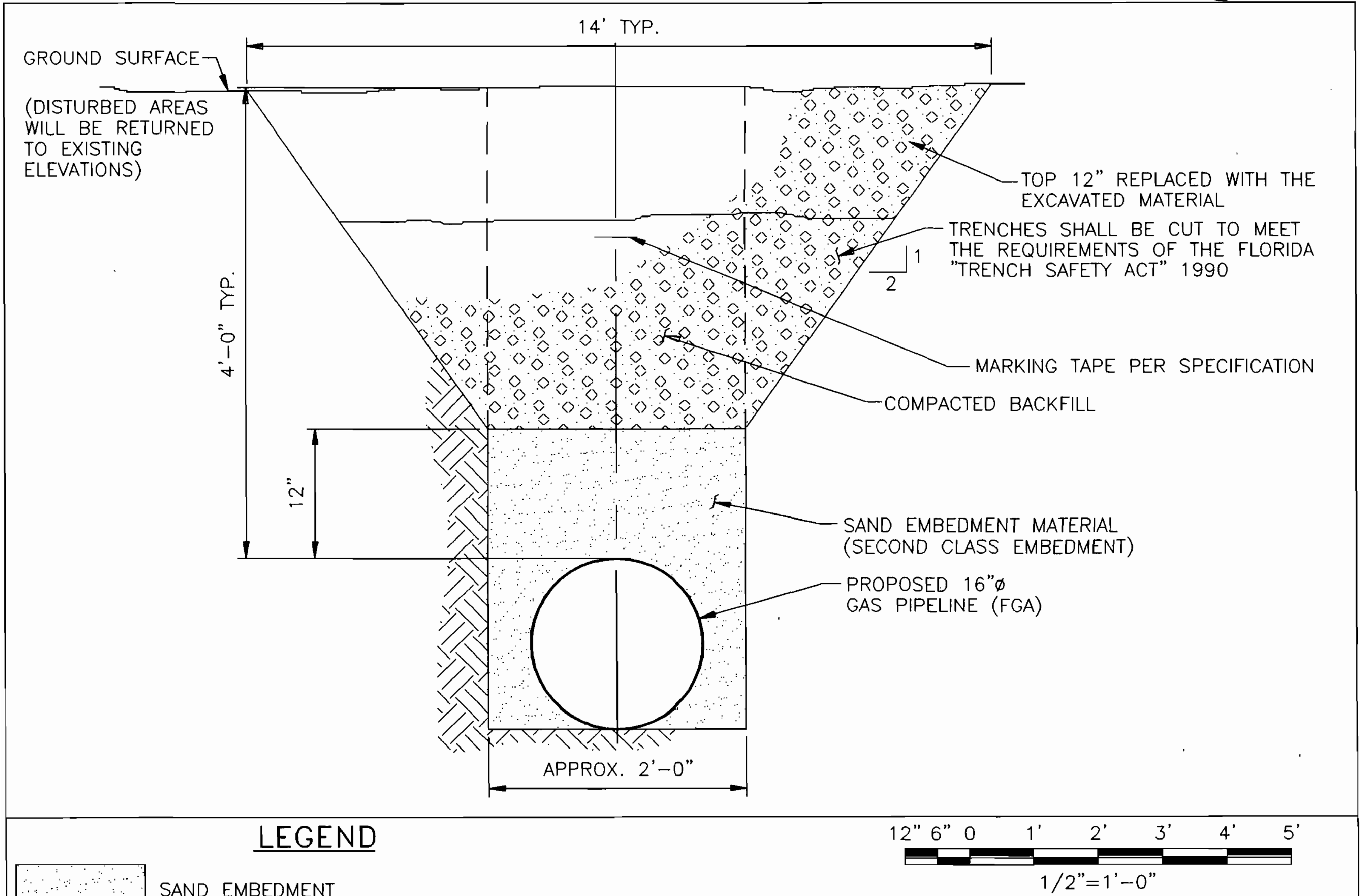

Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)



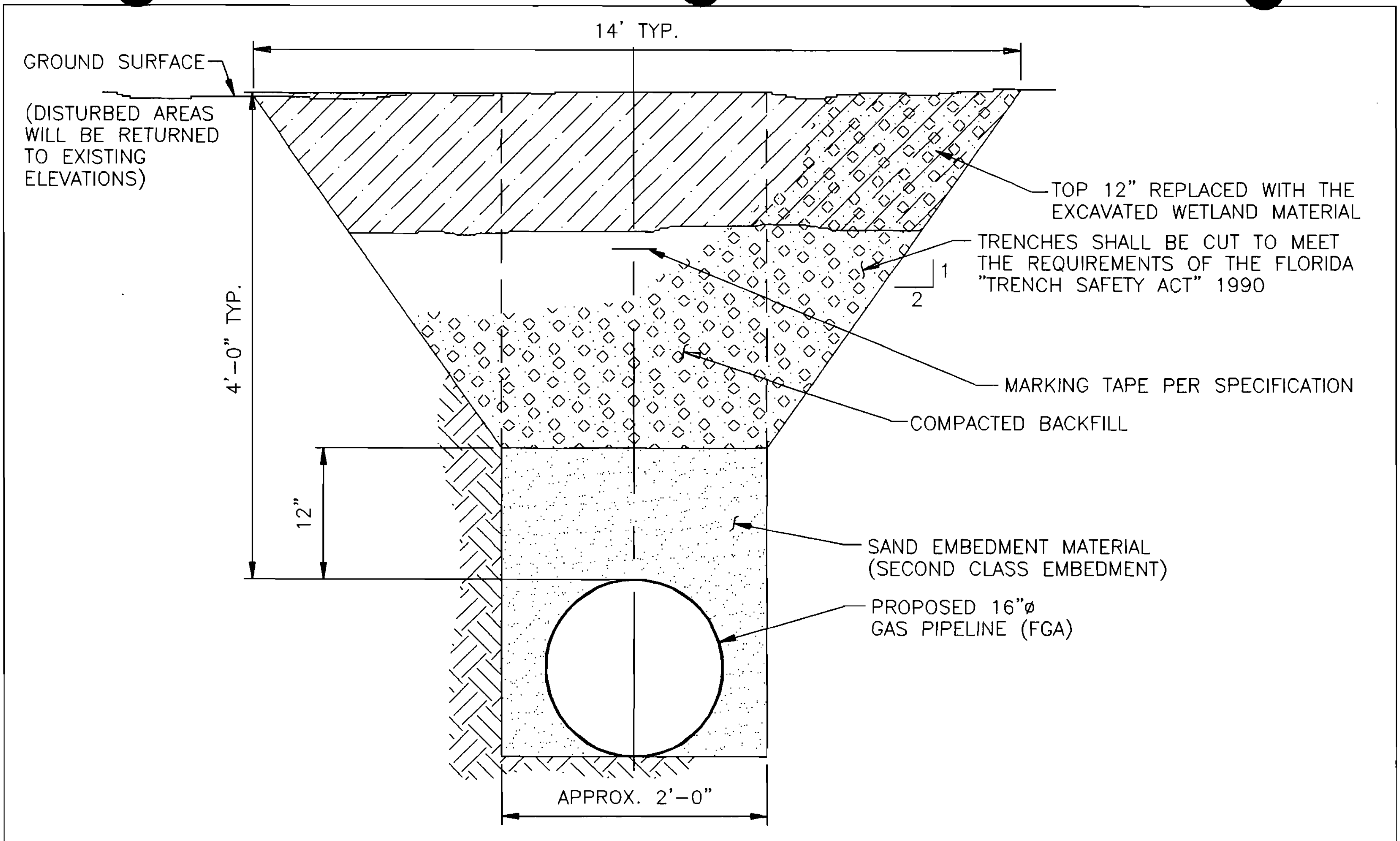

# Stanton Energy Center
# Property Location
# Figure 6.2-1

Site Location.srf

Gas Line Excavation Drawings:
Figure 6.2-2
Figure 6.2-2A
98362-ERP-4A




TYPICAL GAS LINE TRENCH EXCAVATION
FIGURE 6.2-2 (04-17-2001)




## LEGEND

SAND EMBEDMENT

EXISTING SOIL

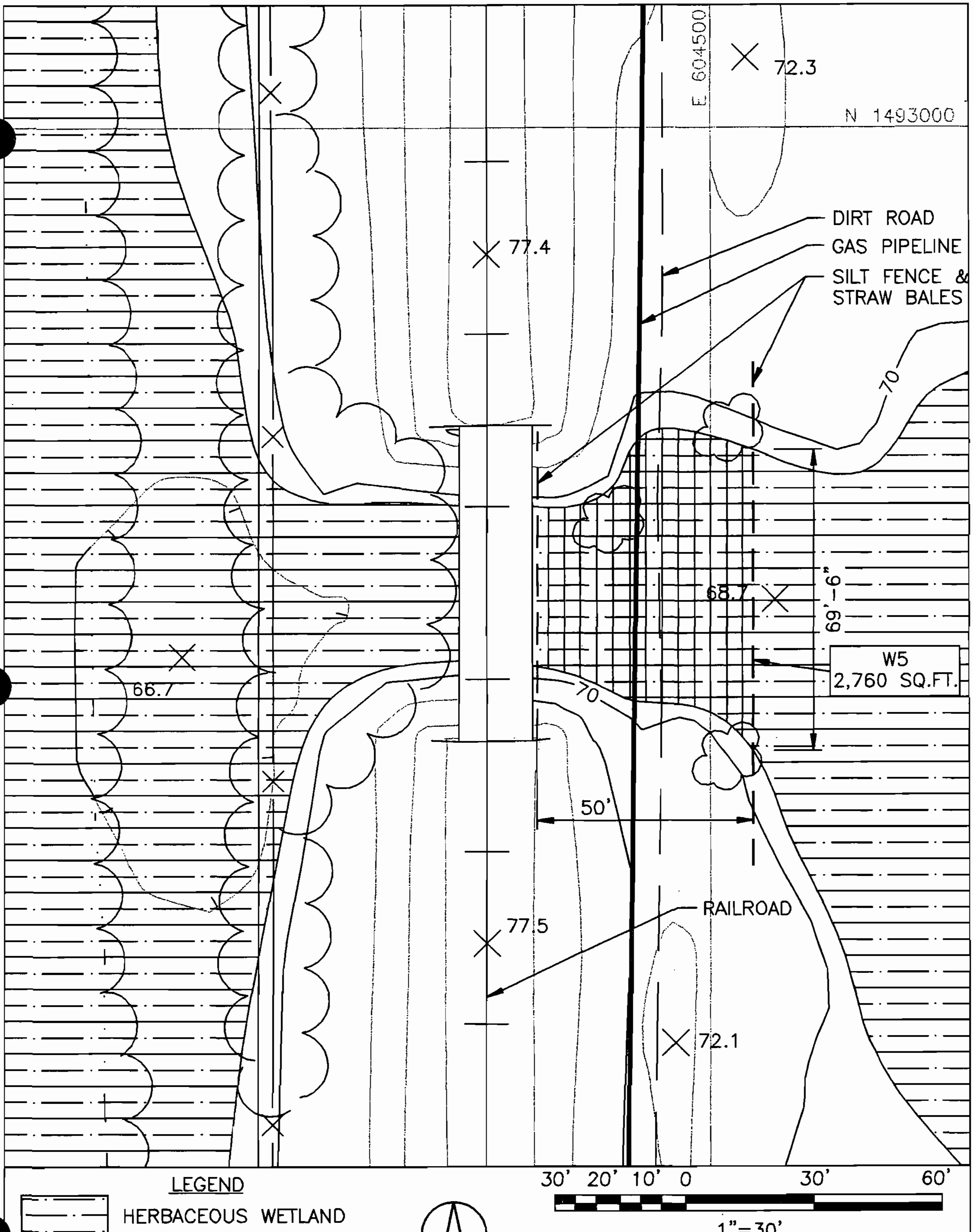
EXISTING WETLAND MATERIAL

COMPACTED BACKFILL

12" 6" 0 1' 2' 3' 4' 5'

1/2"=1'-0"

TYPICAL WETLAND TRENCH EXCAVATION
FIGURE 6.2-2A (04-17-2001)




SEC COMBINED CYCLE PROJECT
WETLAND IMPACT AREA W5
DRAWING 98362-ERP-4A (04-17-2001)

FDEP Bureau of Public Land Administration
Letter

# Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

March 13, 2001

Lainie Krop
Black & Veatch
11401 Lamar Avenue
Overland Park, Kansas
66211

RE: Stanton Energy Pipeline

Dear Ms. Krop:

After reviewing the report from our Title and Land Records Section, The Bureau of Public Land Administration formed an opinion that, in the absence of any unknown information to the contrary, The State of Florida has no claim to lands on which The Stanton Energy Center proposes to lay a pipeline. Those lands include: sections 13, 23, 24, 25, and 36 of township 23 south, range 31 east; sections 18, 19, 30, and 31 of township 23 south, range 32 east; section 1 of township 24 south, range 31 east; and section 6 of township 24 south, range 32 east. However, The State of Florida holds the deed on a parcel of land in section 30/township 23 south/range 32 east. The deed does not include the west 300 feet of section 30, so our opinion is that the proposed pipeline will not encroach on state lands, assuming the pipeline will cover only 150 feet on each side of the section line. Additionally, our Title Department recommended that the proprietary requirements normally applied to state owned lands not be applied to two branches of the Econlockhatchee Creek. If these waters are deemed navigable in the future, then the proprietary requirements regarding state owned water bodies would apply to the proposed activity.

I hope this is all the information you needed. Please let me know if I can help you in any other ways with this project or with future projects. Thanks for your patience.

Respectfully Yours,

M. Wayne Patton
Bureau of Public Land Administration
Division of State Lands

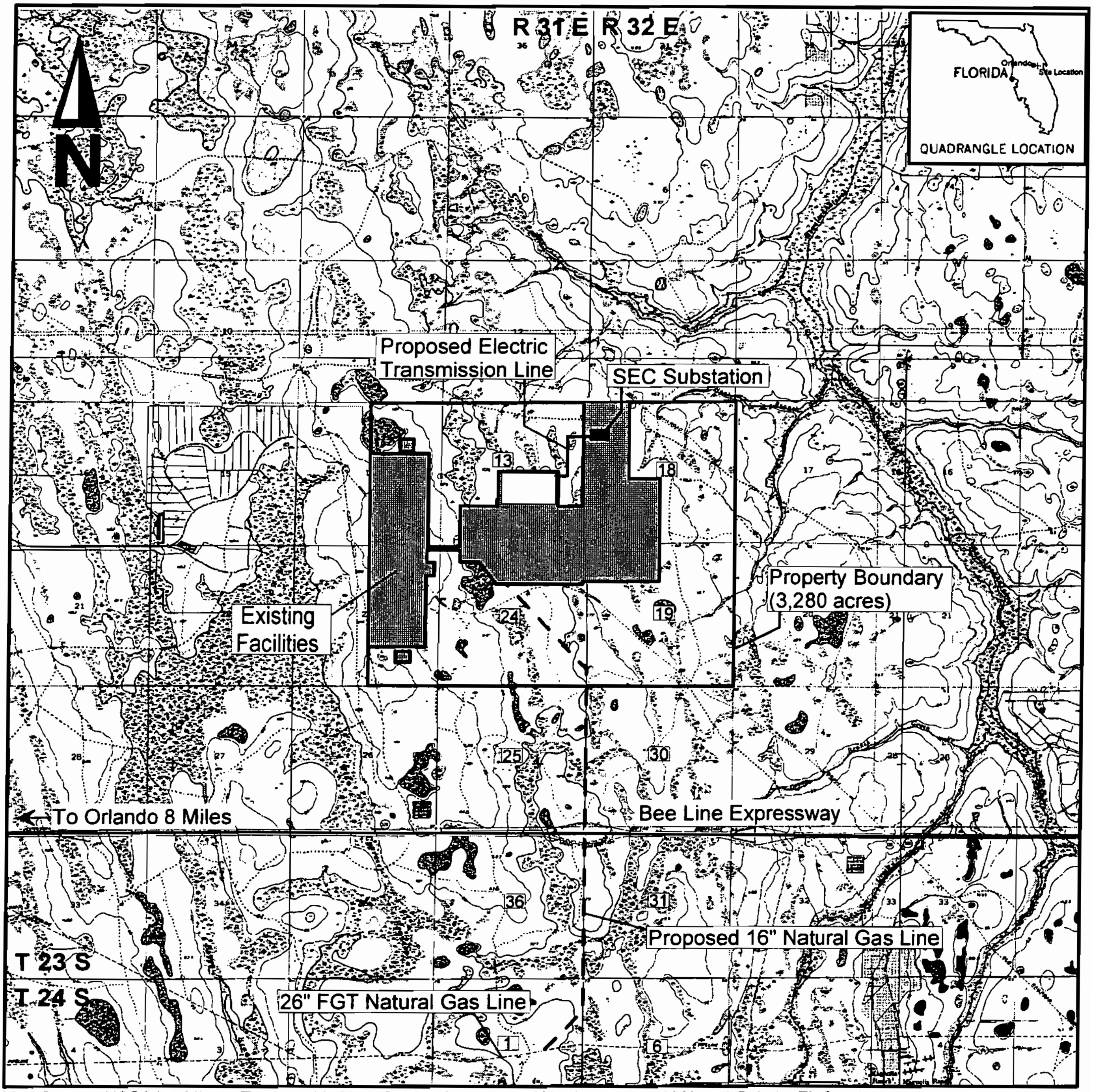
mwp
enclosure (1)

COMMENTS: THE STATE HAS NO CLAIM TO ANY UPLANDS LOCATED AT THE AREA IN QUESTION. RECORDS ON FILE WITHIN THE TITLE & LAND RECORDS SECTION INDICATE THAT ALL OF SECTIONS 13, 14, 23 & 24 OF T23S/31E WERE CONVEYED TO A PRIVATE PARTY BY VIRTUE OF DEED # 10411, AND ALL OF SECTIONS 18 & 19 OF T23S/32E WERE CONVEYED TO A PRIVATE PARTY BY VIRTUE OF DEED # 12017. FOR THE HART BRANCH AND THE COWPENS BRANCH OF THE ECONLOCKHATCHEE CREEK IN THE AREAS OF THE PROPOSED ACTIVITY, WE RECOMMEND THAT THE PROPRIETARY REQUIREMENTS THAT WOULD NORMALLY APPLY TO STATE OWNED LANDS NOT BE APPLIED TO THESE WATERBODIES. IF, IN THE FUTURE, THE SUBJECT WATERBODIES ARE DETERMINED TO BE NAVIGABLE AND THEREFORE STATE OWNED, THEN THE PROPRIETARY REQUIREMENTS ESTABLISHED BY THE BOARD REGARDING STATE OWNED WATERBODIES WILL APPLY TO THE PROPOSED ACTIVITY. THE SITE IS NOT LOCATED WITHIN AN AQUATIC PRESERVE. COPIES ATTACHED. JCJ 01/29/01 TO: STEVE REMKE, PLA

JCJ 02/22/01
AN ADDITIONAL REQUEST WAS MADE FOR A TITLE REVIEW OF A PROPOSED GAS LINE IN THE AREAS COVERED IN THE INITIAL REQUEST, AS WELL AS IN THE FOLLOWING AREAS: T23S/R31E/25 & 36, T23S/R32E/30 & 31, T24S/31E/1, & T24S/32E/6. THE ADDITIONAL REMARKS IN THIS REVIEW ARE BASED ON AN APPROXIMATE LOCATION OF THE PROPOSED GAS CORRIDOR, BECAUSE THE REQUESTOR DID NOT PROVIDE AN ACTUAL DESCRIPTION FOR THE PROPOSED CORRIDOR. RECORDS ON FILE WITHIN THE TITLE & LAND RECORDS SECTION INDICATE THAT ALL OF T23S/R31E/25 & 36 AND T24S/31E/1 WERE CONVEYED TO A PRIVATE PARTY BY VIRTUE OF DEED # 10411. ALL OF T23S/R32E/30 & 31 AND T24S/32E/6 WERE CONVEYED TO A PRIVATE PARTY BY VIRTUE OF DEED # 12017. THE STATE HAS NO CLAIM TO THE UPLANDS IN THESE SECTIONS EXCEPT FOR A PORTION OF SECTION 30 IN T23S/R32E AS DESCRIBED IN A DEED TO THE TIITF (OR BK 3427/PG 1809) DATED OCTOBER 6, 1983. THIS DEED DOES NOT INCLUDE THE WEST 300 FEET OF SECTION 30. HOWEVER, THE PARCEL OF UPLANDS COVERED IN THE DEED IS ALSO SUBJECT TO LEASE # 3339 TO THE DEPT. OF CORRECTIONS. COPIES ATTACHED.

PREPARER: JAMES C. JENKINS
DATE PREPARED: 02 / 06 / 2001

Location Maps:
Figure 2
Figure 8




Map Source: USGS 7.5 Minute Topographic Map (Bithlo, Narcoossee NE, Narcoossee NW, and Oviedo, FL Quadrangles)

Miles

0 1 2 3

# Stanton Energy Center
# Property Location
# Figure 2

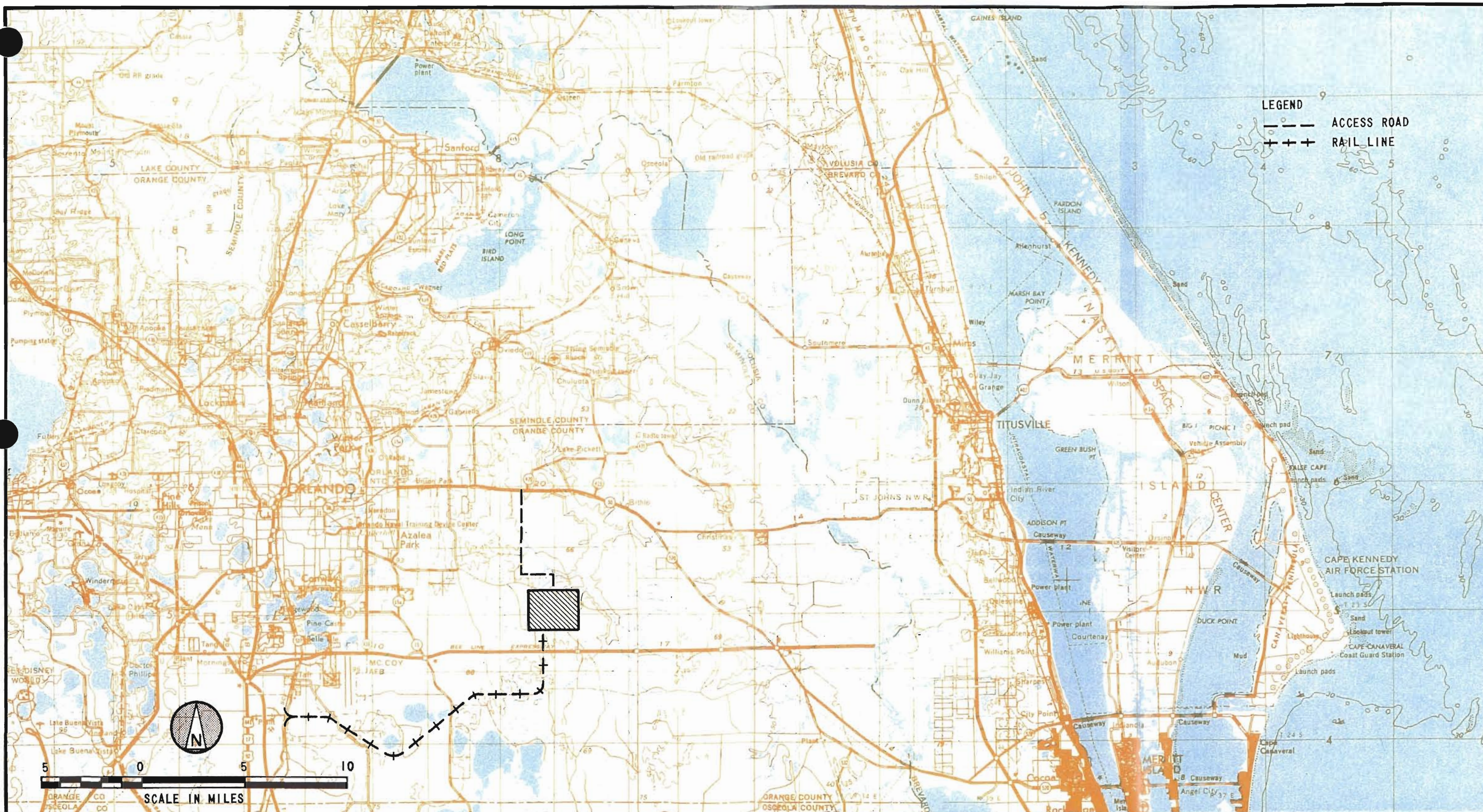



FIGURE 8
REGIONAL AREA MAP

**St. Johns River Water Management District**

1. *District water use rules require that the lowest acceptable quality water source, including reclaimed water or surface water (which includes storm water), must be utilized for each consumptive use. To use a higher quality water source an applicant must demonstrate that the use of all lower quality water sources will not be economically, environmentally or technologically feasible.*

   a) *A source of reclaimed water is readily available from the Orange County Easterly Waste Water Treatment System. Information submitted with the application indicates that this water is intended to be used for cooling uses, but not for all uses. Please demonstrate why it is not feasible to use reclaimed water for all uses except for potable water. In order to demonstrate that the use of a lower quality source is not economically feasible, the applicant must demonstrate in detail that the use would render the entire project economically unfeasible. [Section 10.3 (e)(f)(g), Applicant's Handbook, Consumptive Uses of Water (February 8, 1999) (A.H.)]*

   b) *A source of storm water is available from the adjacent Orange County Landfill to meet some of the power plant's water needs. Please evaluate the feasibility of using this source. In order to demonstrate that the use of a lower quality source is not economically feasible, the applicant must demonstrate in detail that the use would render the entire project economically unfeasible. [Section 10.3(e)(f)(g), A.H.]*

   c) *The applicant includes a request for 2.13 million gallons per day of groundwater from the Floridan aquifer for cooling water use during emergency conditions. The existing power plant facility includes an approximately 90-acre storage pond with approximately 146 million gallons of storage capacity. The Orange County Easterly Waste Water Facility has an emergency groundwater backup allocation of 100 million gallon per year. Orange County applied for renewal of this permit with the same allocation. That permit application is complete and will be recommended for approval. Please demonstrate why it is not feasible to use either the water in the existing storage pond or the emergency groundwater backup allocation for the Orange County Waste Water Facility for the requested emergency backup use. [Section 10.3(e)(f)(g), A.H.]*

**Response 1a:** The existing Stanton water treatment system was originally designed to treat groundwater, and is not currently capable of treating the Orange County effluent. An entirely new pretreatment and demineralizer system would be required to remove organics and other foulants and render the effluent usable for Stanton A demineralized water makeup supply. A new demineralized water treatment system is estimated to cost approximately $5 million and is not required because the existing demineralizer system has adequate capacity for Stanton A.

However, the applicants are amenable to accepting no increase in the current site allocation of groundwater as long as Orange County landfill stormwater of adequate quality is delivered to an appropriate location at the Stanton site. OUC will evaluate reuse and treatment on a site-wide basis to determine the best alternatives to avoid increase in groundwater consumption.

**Response 1b:** The applicants are committed to evaluating the potential use of stormwater from the Orange County Landfill for power plant operations. As described above, the existing Stanton water treatment system is not currently capable of treating waters significantly different from the design groundwater. However, OUC will accept the stormwater as a supplemental makeup source for power plant operations if the stormwater meets certain quality standards and Orange County delivers the stormwater to an appropriate location at the Stanton site, as determined by OUC, at no burden to the applicants.

**Response 1c:** The applicants will withdraw the request for emergency use of groundwater pending approval of the Orange County Easterly Waste Water Facility emergency allocation and agreement for the delivery/use of Orange County Landfill stormwater of adequate quality. The availability of this water provides adequate assurance of cooling water supply in the event of an effluent shortage.

2. *The applicant has completed an initial evaluation that includes simulations of the drawdown in the Floridan aquifer due to the average daily withdrawal from all three units and of the drawdown due to the maximum combined capacity of the onsite wells pumping continuously for 30 days. Please provide copies of the input and output files for these model simulations. Additional impact analyses are necessary as follows:*

- *An analysis to evaluate the cumulative drawdown impacts of the proposed withdrawals in combination with withdrawals from all existing legal uses.*

- *An analysis to evaluate the cumulative impacts of the proposed withdrawals in combination with withdrawals from all existing legal uses and all withdrawals requested by applicants whose applications are complete. This analysis is necessary to determine whether there are competing applications.*

- *An analysis to evaluate the cumulative impacts due to all existing and reasonably anticipated uses at some future year or years, including the proposed withdrawals. This can be in multiple evaluations such as for years 2005, 2010, and 2020. The purpose of this evaluation is to address the sustainability of the resource.*

**Response:** As part of the Curtis Stanton Energy Center Combined Cycle Unit Power Plant Siting Supplemental Application No. PA 81-14SA2, Black & Veatch developed a site-specific groundwater model, performed model simulations, and submitted model results to Florida DEP. Black & Veatch's model simulation was based on estimated transmissivity of 72,000 $ft^2$/day for the Upper Foridan Aquifer. Site borehole data indicate the presence of a confining unit (Hawthorn Formation) between the unconfined aquifer and the Upper Foridan Aquifer. A detailed discussion of the geology and hydrogeology is presented in the Siting Supplemental Application, and will not be repeated herein.

The primary concern that St. Johns River Water Management District raised was the model did not take into account other pumping wells that may impact the boundary conditions of the local model. Black & Veatch initiated discussions with James Hollingshead, Doug Munch, and Brian McGurk, to get clarification regarding Comment No. 2. James Hollingshead further discussed the issue with Dwight Jenkins and Doug Munch (both with St Johns River Water Management District) and instructed Black & Veatch to complete the following additional tasks:

- Simulate the 1995 steady state condition of St. John River Water Management District's East Central Florida (ECF) Regional Model and document results near the Curtis H. Stanton Power Plant area. The 1995 steady state simulations of the ECF Regional model are based on average annual pumping rates for the plant.

- Simulate the 2020 steady state condition of St. Johns River Water Management District's East Central Florida (ECF) Regional Model and document results near the Curtis H. Stanton Power Plant area. The 2020 steady state simulations of the ECF Regional model are based on average annual pumping rates for the plant.

- Compare the average condition results of the 1995 and 2020 simulations in the unconfined aquifer to see if the 2020 conditions would cause impacts on wetlands over the area surrounding the plant site.

After the remaining modeling tasks were identified, Black & Veatch performed the following tasks:

- Acquired the ECF Regional Model files and simulated 1995 and 2020 boundary conditions.

- Created local models using the 1995 and 2020 ECF Regional Model conditions in the vicinity of the plant, and the 1995 and 2020 ECF Regional Model boundary conditions.

- Simulated the 1995 and 2020 conditions and documented results as requested.

- Simulated and documented plant increased well pumping conditions.

- Prepared model input and output files for submittal as requested.

The tasks were completed to fully address the modeling comments. The completed modeling tasks and the results are discussed in the following text.

**Data Collection**
Black & Veatch contacted the Regional Modeling Group of St. Johns River Water Management District and acquired free format files of the ECF MODFLOW model. The ECF model files included steady state simulated heads for 1995 and 2020 conditions.

**Formulation of a Local Model**
The local model was created to simulate and evaluate results in the vicinity of the plant. The approximate plant area within the regional model is shown on Figure 1. The ECF Regional Model contains 174 rows, 194 columns, and 4 layers. The dimensions of each grid cell of the ECF model are 2,500 by 2,500 feet. The Stanton Plant wells are located at row 94, column 109, and layer 2 of the ECF Regional Model.

Using the configuration and results of the ECF model created by St. John River Water Management District, Black & Veatch created a local model. The local model was created using GMS-MODFLOW Version 3.1. Groundwater Modeling Software (GMS) is a pre-, post processing software that is widely used with MODFLOW and other modeling packages.

**Model Area**
The local model consists of an 11 by 11 grid model of the ECF Regional Model, which covers an area of approximately 5 by 5 miles. The grid spacing in the X and Y directions is 2,500 feet, similar to the ECF Regional Model. The local model grid, with the row, column, and layer indices is shown on Figure 2. The grid cell containing the two plant wells is at the center of the local model (Row 6, Column 6, and Layer 2).

**Model Layers**
The simulated aquifers include the Surficial Aquifer System (SAS) and the Floridan Aquifer System (FAS). The SAS is referred to as the unconfined aquifer in the Site Supplemental Application. The local model layers are similar to the ECF Regional Model, with the SAS modeled as Layer 1, the Upper Floridan Aquifer modeled as Layers 2 and 3, and the Lower Floridan Aquifer modeled as Layer 4.

**Model Boundaries**
The perimeter boundary heads of the local model were specified and are equal to the ECF Regional Model simulated heads at the local model boundaries. The ECF

Regional Model simulation results indicated that layer 1 heads over the local model area are essentially the same for 1995 and 2020 conditions while the potentiometric levels in the Upper Florican Aquifer dropped approximately 6 feet. The stability of the SAS groundwater elevations during significant changes in the Upper Floridan Aquifer levels, indicates that the SAS is basically independent of the Upper Floridan Aquifer over the local model area. This is supported by the following:

- The presence of the Hawthorn formation between the SAS and the Upper Floridan Aquifer, as identified during subsurface investigations performed by Black & Veatch.
- Prior pump testing performed by Black & Veatch.
- Prior groundwater modeling performed by Black & Veatch.

Consequently, heads in layer 1 of the local model were imported from the ECF Regional Model and specified.

Because the 1995 and the 2020 simulations of the regional model result in two separate boundary conditions for the local model, two separate local models were created to evaluate and compare the local conditions for the two time periods. The only difference between the two local models was that, one used the 1995 boundary conditions, while the other used the 2020 boundary conditions.

**Hydraulic Parameters**

The ECF Regional Model properties were assigned to each corresponding grid cell of the local model in layers one through four. This was accomplished by importing the appropriate cell regional model layer configurations, and properties. The imported configurations and properties included layer top/bottom elevations, hydraulic conductivities, and leakances between layers. The model parameters for layers one through four of the grid cell containing the plant wells are shown in Table 1.

**Table 1**
**Local Model Parameters and Layer Elevations at the Plant Wells Grid Cell**

| Model Layer | Layer | Top Elevation | Bottom Elevation | Horizontal Hydraulic | Leakance |
|---|---|---|---|---|---|
| Number | Designation | (NGVD, Feet) | (NGVD, Feet) | Conductivity (ft/day) | (VCONT) |
| 1 | SAS | 80 | 5 | 60 | 5.00E-06 |
| 2 | Upper FAS | 5 | -339 | 250 | 1.17E-02 |
| 3 | Upper FAS | -339 | -467 | 1,750 | 1.55E-04 |
| 4 | Lower FAS | -467 | -1,663 | 75 | NU |

NU = Not Used in Model

The model developed based on the ECF Regional Model agrees well with the model previously developed by Black & Veatch. Using the ECF Regional Model, the transmissivity of the Upper Floridan Aquifer at the plant wells location is 86,250 $ft^2$/day. This is in good agreement with the previous Black & Veatch estimated transmissivity of 72,000 $ft^2$/day. The 5.00E-06 leakance value between the SAS and the Upper Floridan Aquifer at the plant wells location is also in good agreement with Black & Veatch's documented presence of the Hawthorn Formation located between the SAS (unconfined aquifer) and the Upper Floridan Aquifer.

**Simulation of 1995 Conditions with a Local Model**

For all four layers, the 1995 local model perimeter boundary heads were specified, and were equal to the ECF model simulated heads for 1995. Heads in layer 1 of the local model were imported from the ECF Regional Model and specified. The layer 1 specified heads allow comparison of the 1995 and 2020 ECF Regional Model results over the local model area. The perimeter boundary heads from the ECF Regional Model establish conditions that take into account the impact of pumping wells located outside the local model area.

Pumping of wells within the area of the local model was set to match the locations and pumping rates in the 1995 ECF Regional Model. This resulted in pumping water from two grid cells from layer 2. The first pumping location is found at ECF Regional Model Row 94, Column 109, and includes the two Stanton plant wells pumping at the present average day total rate of 49,501 $ft^3$/day (257 gpm). The other location is a well approximately 1.25 miles southeast of the plant wells at ECF Regional Model Row 95, Column 111, and includes pumping at a rate of 13,934 $ft^3$/day (72.4 gpm).

The SAS (unconfined aquifer) water level contours over the local model area for 1995 are shown in Figure 3. The water table above the cell containing the plant wells is at approximately elevation 75 feet. Over the 5 by 5-mile local model area, the water table elevations range from 40 feet to 80 feet. The simulated water table is higher than elevation 80 feet over an area of approximately 1 by 2.5 miles west of the plant. This may be the location of a local water table divide. East of this divide, flow is generally from southwest to northeast with an approximate hydraulic gradient of 0.001.

Simulated 1995 potentiometric contours for the Upper Floridan Aquifer (local model layer 2) are presented in Figure 4. These local model simulated potentiometric elevations for the Upper Floridan Aquifer are in agreement with the potentiometric elevations of the ECF Regional Model. Simulated potentiometric elevations range from 38 feet on the northeast portion of the modeled area to 44 feet on the southwest portion of the modeled area; therefore, groundwater flow is from southwest to northeast. Pumping from the wells at the

Stanton Energy Center has very little local influence on the general groundwater flow, as can be observed in Figure 4.

**Simulation of 2020 Conditions with a Local Model**

The local model to simulate the 2020 condition was created using the ECF Regional Model simulated heads for the year 2020. Similar to the 1995 local model, the perimeter boundary heads for all layers and the water table heads in layer 1 were specified based on the ECF Regional Model. The 2020 local model was simulated using the 2020 pumping conditions established in the ECF Regional Model, which was the same for the two grid cells where pumping occurred for the 1995 local model. No additional pumping locations were required for the local 2020 model, because none were added to the 2020 ECF Regional Model within the area of the local model. Therefore, pumping within the 1995 and 2020 local models was the same, but the perimeter boundary conditions differed due to pumping differences outside the boundaries of the local model areas.

The 2020 SAS (unconfined aquifer) water level contours over the local model area which were simulated by the ECF Regional Model are shown in Figure 5. The simulated water table elevations are almost identical to the 1995 water table elevations shown on Figure 3. The water table above the cell containing the plant wells is at approximately elevation 75 feet. Over the 5 by 5 mile local model area, the water table elevations range from 40 to 80 feet. As for 1995, over an area of approximately 1 by 2.5 miles west of the plant, the simulated water table is high and appears to create a divide. East of this divide, flow is generally from southwest to northeast with an approximate hydraulic gradient of 0.001.

The simulated 2020 potentiometric elevations in the Upper Floridan Aquifer are lower than the 1995 potentiometric elevations. Simulated potentiometric contours for 2020 for the Upper Floridan Aquifer are presented on Figure 6. These local model simulated potentiometric elevations for the Upper Floridan Aquifer are in agreement with the potentiometric elevations of the ECF Regional Model. Simulated potentiometric elevations range from approximately 33 feet on the northeast portion of the modeled area to 37 feet on the southwest portion of the modeled area. The 2020 potentiometric elevations in the Upper Floridan Aquifer are lower than in 1995 by approximately 6 feet. However, the 2020 groundwater flow direction, from southwest to northeast, is similar to that in 1995. Review of the contours in Figure 6 shows present plant pumping has very little impact on the potentiometric level and hydraulic gradient of the Upper Floridan Aquifer.

**Comparison of Local Area 1995 and 2020 Simulation Results for the SAS**

The ECF Regional Model generated groundwater elevation contours for 2020 and 1995 for the SAS (unconfined aquifer) are almost identical. Figure 7 presents differences in water table elevations between 1995 (Figure 3) and 2020 (Figure 5). Absolute differences in water table elevations between the two conditions within the 5 by 5-mile local area range from 0.05 foot to 0.08 feet.

These results indicate that the elevation of the groundwater in the SAS (unconfined aquifer) is not impacted over the local area by the increase in pumping from the Upper Floridan Aquifer that is anticipated from 1995 to 2020. This is shown by the consistent level of the SAS groundwater elevations, even though the potentiometric level of the Upper Floridan Aquifer drops 6 feet between 1995 and 2020. Since the elevation of the groundwater in the SAS is constant for 1995 and 2020, this also demonstrates that wetlands in the plant vicinity will not be impacted by the additional 2020 aquifer stresses. No impact on the SAS was also predicted by the earlier Black & Veatch model, which showed no lowering of the SAS water levels due to pumping from the Upper Floridan Aquifer. Additionally, well monitoring within the SAS during a pump test at the Stanton Energy Center showed no lowering of the SAS water level during the pump test.

The presence of the Hawthorn Formation in the plant site vicinity is the reason for the limited hydraulic interaction between the SAS (unconfined aquifer) and the Upper Floridan Aquifer.

**Simulation of Additional Plant Pumping**

The projected additional pumping associated with the third unit at the Stanton Energy Center was superimposed on the 2020 local model and evaluated. To evaluate this scenario, the average pumping rate at the plant wells was increased from 251 gpm (used in the ECF Regional Model) to 551 gpm projected in the Supplemental Site Certification Application. Figure 8 shows the potentiometric contours for the Upper Floridan Aquifer when pumping is increased to the projected average rate. Closer contour spacing is shown in the vicinity of the plant to better show the impact of the additional pumping. The contours clearly indicate that the additional pumping has a minor, very local impact on the potentiometric levels in the Upper Floridan Aquifer.

Figure 9 shows potentiometric level differences for the Upper Floridan Aquifer between potentiometric elevations for the present plant pumping rate and potentiometric elevations for the projected increased plant pumping rate. The additional drawdown in the Upper Floridan Aquifer due to the increased pumping rate is only 0.30 feet at the grid containing the plant wells and 0.15 feet at approximately 2,500 feet from the plant wells. At 1.5 miles from the plant pumping wells there is essentially no additional drawdown due to the increased pumping rate. Based on the lack of impact due to lowering of the Upper Floridan Aquifer 6 feet, the additional 0.3 feet drawdown in the Upper Floridan Aquifer will not have any impact on the SAS (unconfined aquifer).

**Summary and Conclusion**
Black & Veatch has completed and documented hydraulic modeling results to address the comments on its first submitted model.

- The 1995 and 2020 water table elevations in the SAS (unconfined aquifer) have been presented from the ECF Regional Model simulated results.

- Appropriate boundary conditions from the ECF Regional Model were used to create the local 1995 and the 2020 models. Simulations were completed using these boundary conditions.

- Comparison of the 1995 and 2020 ECF Regional Model results indicate no change in SAS (unconfined aquifer) water table elevations between 1995 and 2020 within the 5 by 5 mile area of the local model, even though the potentiometric level of the Upper Floridan Aquifer is projected to drop 6 feet. Consequently, wetlands in the vicinity of the plant will not be impacted as a result of increased pumping from the Upper Floridan Aquifer from 1995 to 2020.

- The proposed increase in water use for Stanton A at the Stanton Energy Center will not affect groundwater elevations in the SAS (unconfined aquifer); therefore, wetlands, and environmental features that have direct or indirect relationship to wetland habitats for rare, endangered, or threatened species will not be impacted.

- The increase in groundwater pumping to support Stanton A will have very minimal impact in the Upper Floridan Aquifer. Increased pumping drawdown diminishes within approximately 1.5 miles from the plant pumping wells.

Black & Veatch's modeling results submitted with the Supplemental Site Certification Application are in agreement with the ECF Regional Model.

3. *Is any dewatering of the site anticipated to be required during construction? If so, please confirm that any site dewatering will be below the thresholds in Section 40C-22.030 of the Florida Administrative Code [Sections 10.2(e)(f)(g)(i); 10.3(d)(i), A.H.]*

**Response:** Black & Veatch talked to Charles A. Lobdell, III, Assistant General Counsel of the SJRWMD, to obtain clarification and found that this request is focused on Florida Administrative Code 40C-22.030 (3) (b), which states:

Maximum daily withdrawals for any dewatering activity shall not exceed four million gallons per day (MGD), except during the first 120 hours of dewatering when the daily and instantaneous pumpage rates shall not exceed six MGD. Average daily withdrawal shall not exceed two MGD for the first 60 days of the dewatering activity and shall not exceed one MGD over a 180 day duration.

To respond to the comment, preliminary dewatering estimates for construction of Stanton A were developed.

It is anticipated that dewatering of specific structures will be required during construction of Stanton A. Previous investigations have indicated that the groundwater level of the unconfined aquifer within the site vicinity is approximately at elevation 72.0 feet. Based on an estimated site grade of 79.5 feet, construction dewatering will be required for the following:

- Two oil/water separators placed 15 feet below grade.
- An estimated 12 electrical manholes placed 10 to 12 feet below grade.
- 200 linear feet of circulation water piping placed 10 to 12 feet below grade.

Dewatering for the circulation water piping will be performed for 100 feet of the pipe at a time.

Dewatering for each individual separator, manhole, or individual section of the circulation water piping is considered an individual dewatering activity.

The preliminary dewatering estimates were performed using gravity well drainage equation from NAVFAC Design Manual P-418. It is anticipated that a conventional wellpoint system will be used to accomplish the dewatering tasks. The estimated dewatering rates for each individual dewatering activity are shown on Table 1.

**Table 1**
**Individual Dewatering Activity Pumping Rates and Durations**

| **Dewatering Activity** | **Estimated Flow Rate** | | **Estimated Dewatering Duration (month)** | **Quantity** |
|---|---|---|---|---|
| | **(gpm)** | **(MGD)** | | |
| Oil / Water Separator | 290 | 0.42 | 1 | 2 |
| Electrical Manholes | 190 | 0.27 | 1 | 12 |
| Circ. Water Pipes (100' section) | 225 | 0.32 | 2 | 2 |

The estimated flow rates in Table 1 for each dewatering activity are below the lowest allowable dewatering discharge rate of 1 MGD for a 180 day duration and are well within compliance with the requirements of Section 40C-22.030 (3) (b).

4. *The information requested for all wells and pumps/surface water sources located on the property must be included in the SOURCES OF WATER Summary Data Sheet. Please also provide information regarding any and all offsite sources (connection points) and surface water pumps associated with the onsite storage pond. [Form 40C-2-1082-1, A.H.]*

**Response:** A revised SOURCES OF WATER Summary Data Sheet is attached, which includes any and all offsite sources and surface water pumps associated with the onsite storage pond.

**Figure 1: Stanton Plant Area Location in the ECF Regional Model**

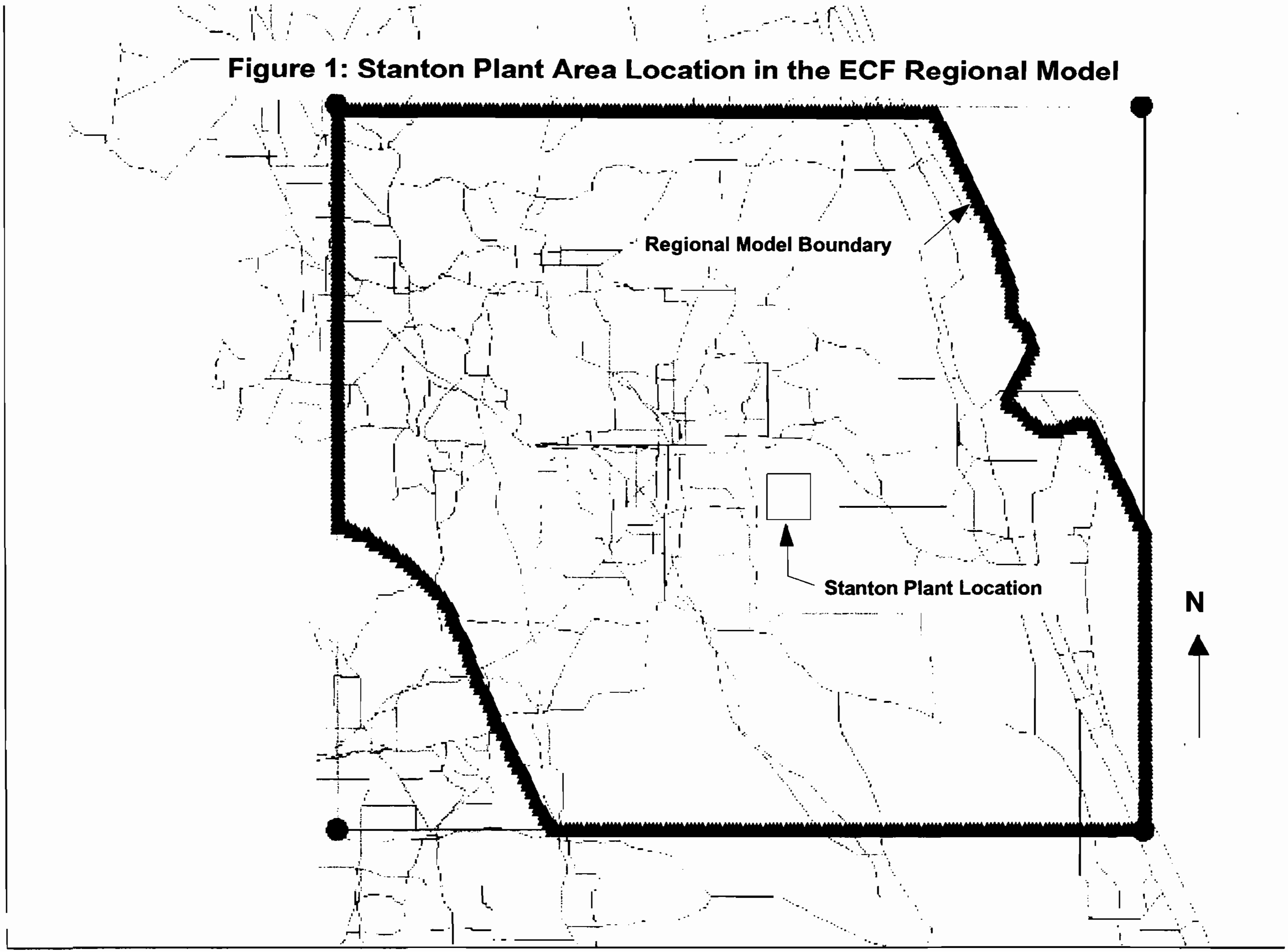


**Figure 2: Local Model Grid, Layer 2, With Row, Column, and Layer Numbers**

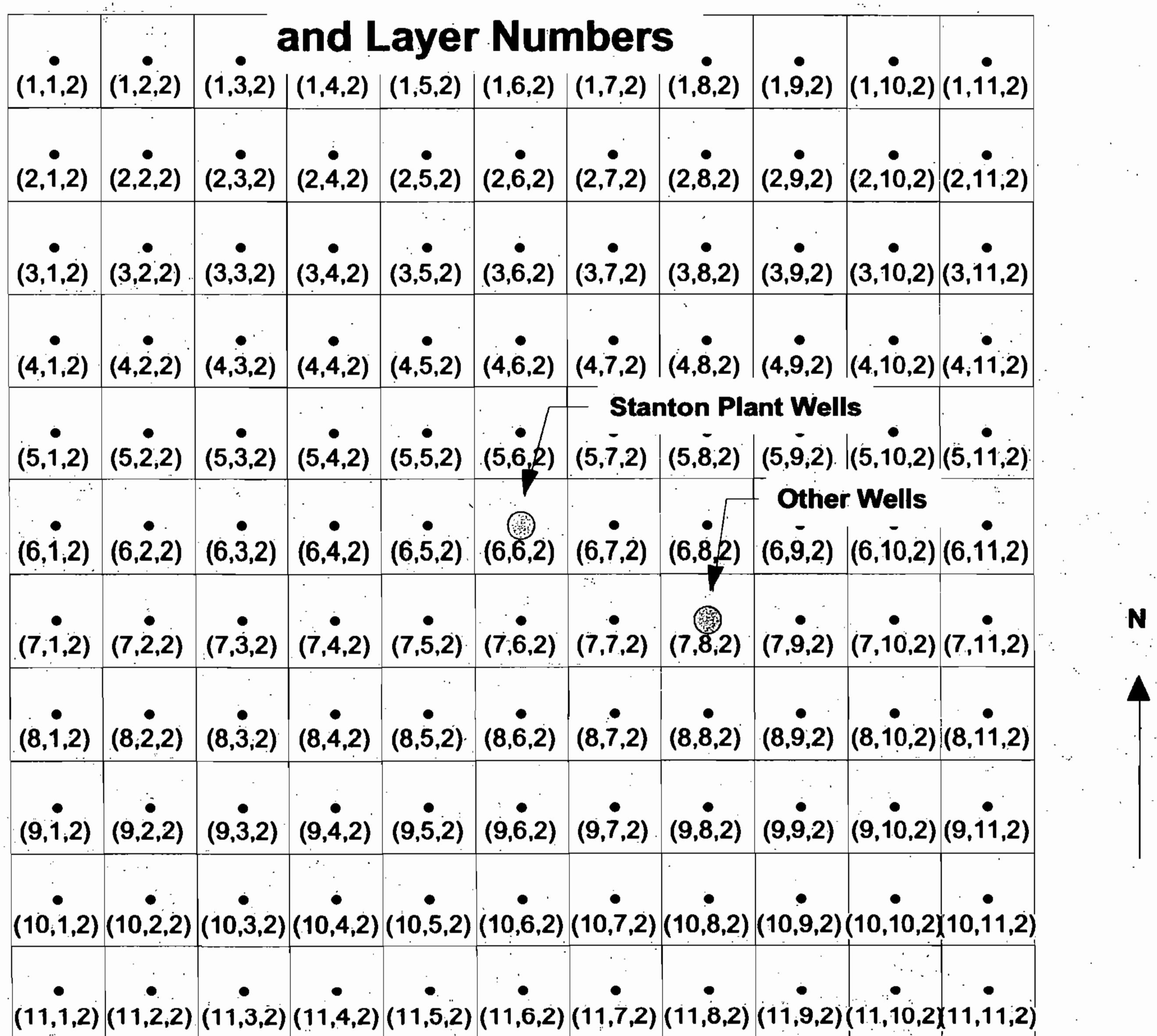
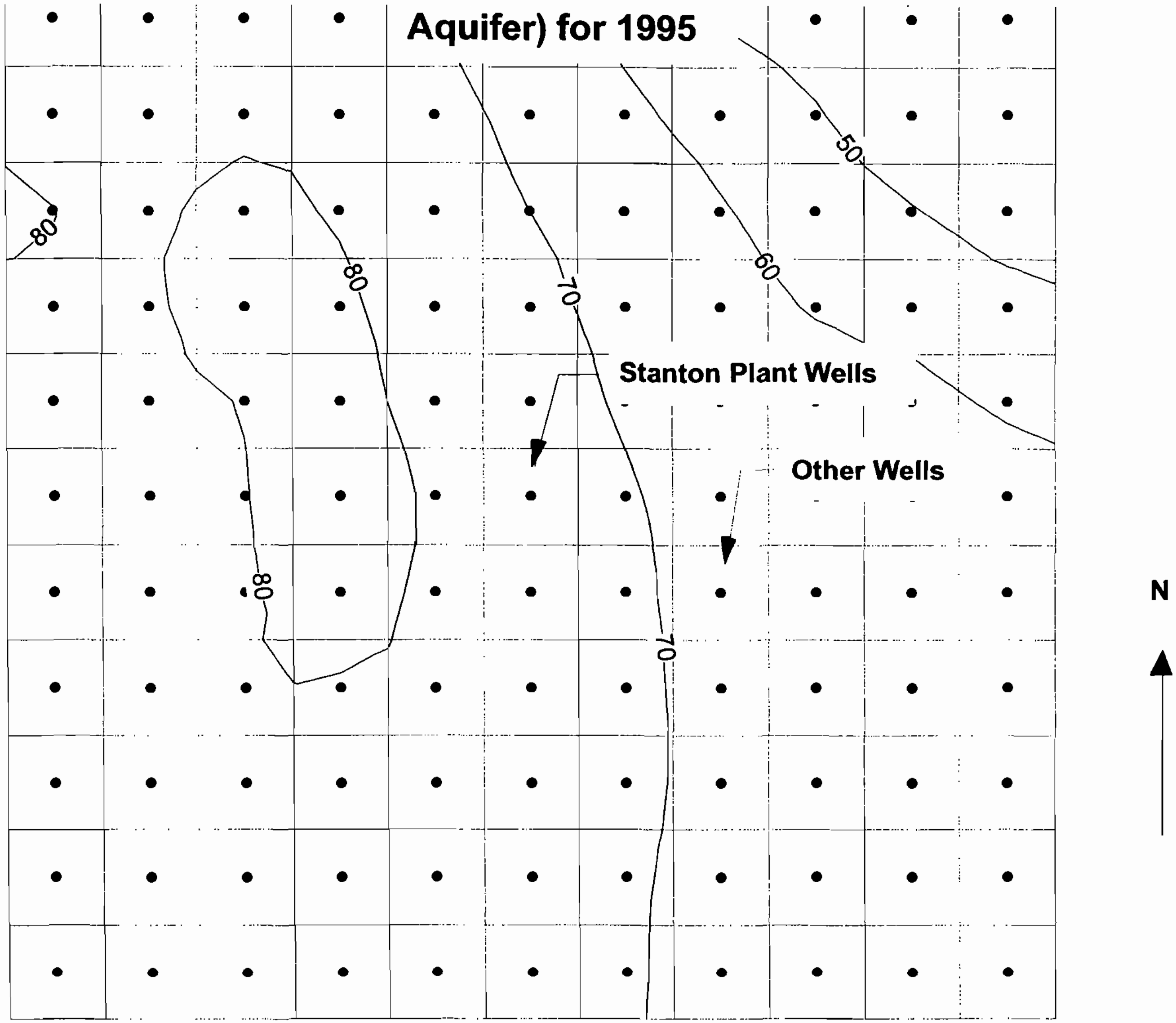


**Figure 3: Water Table Elevation Contours for the SAS (Unconfined Aquifer) for 1995**



## Figure 4: Potentiometric Contours for the Upper Floridan Aquifer for 1995

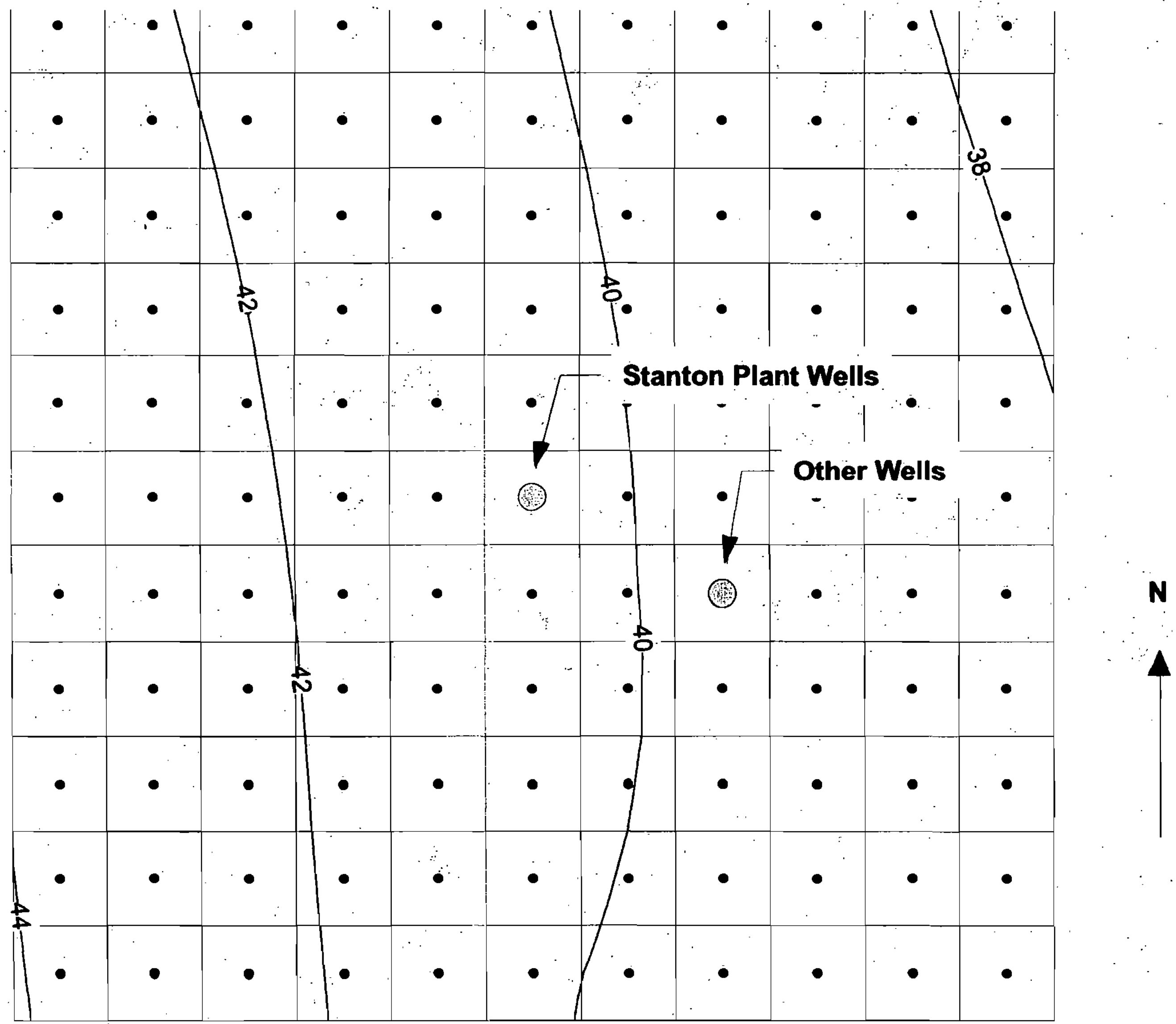


**Figure 5: Water Table Elevation Contours for the SAS (Unconfined Aquifer) for 2020**

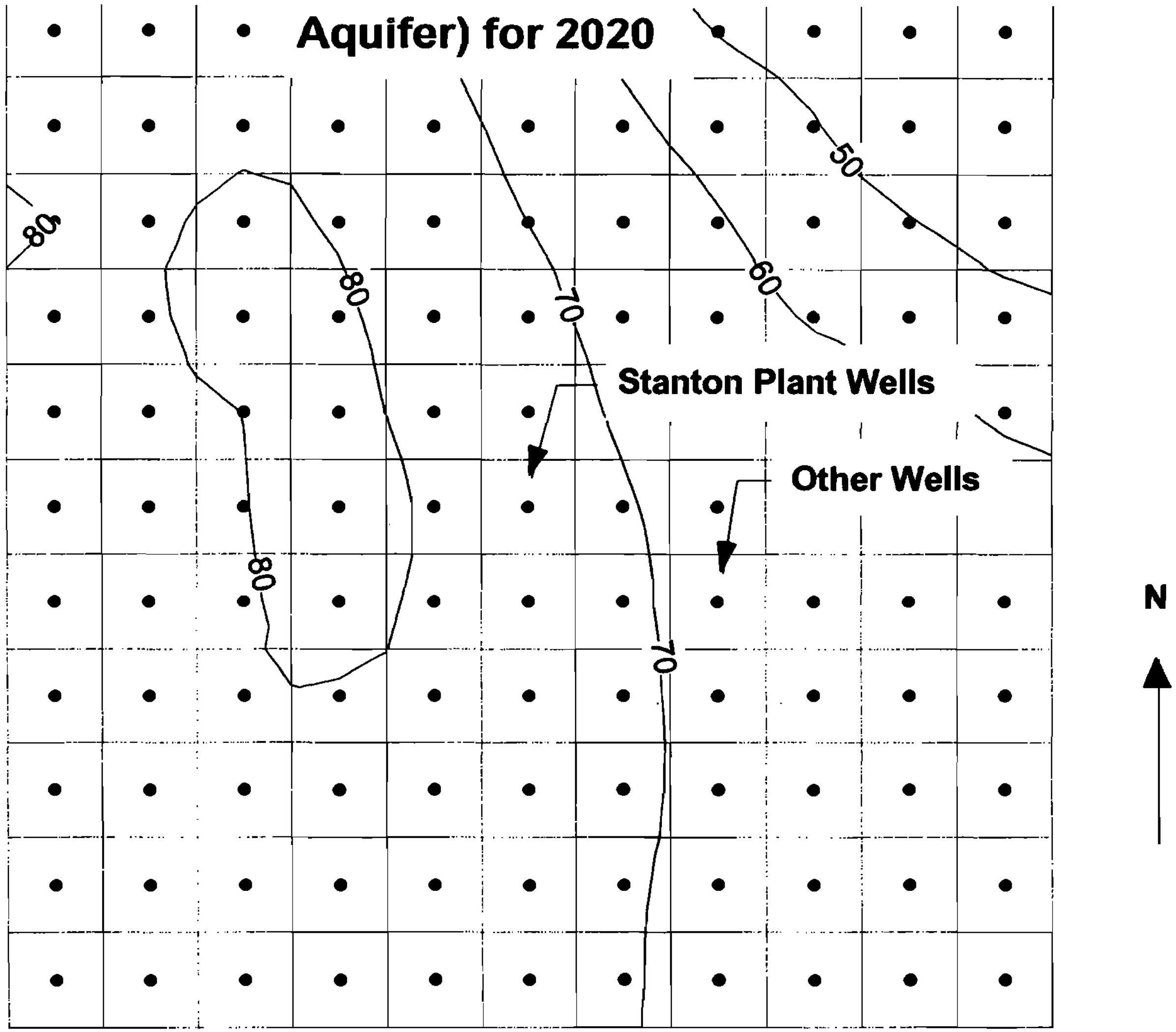


**Figure 6: Potentiometric Contours for the Upper Floridan Aquifer for 2020**

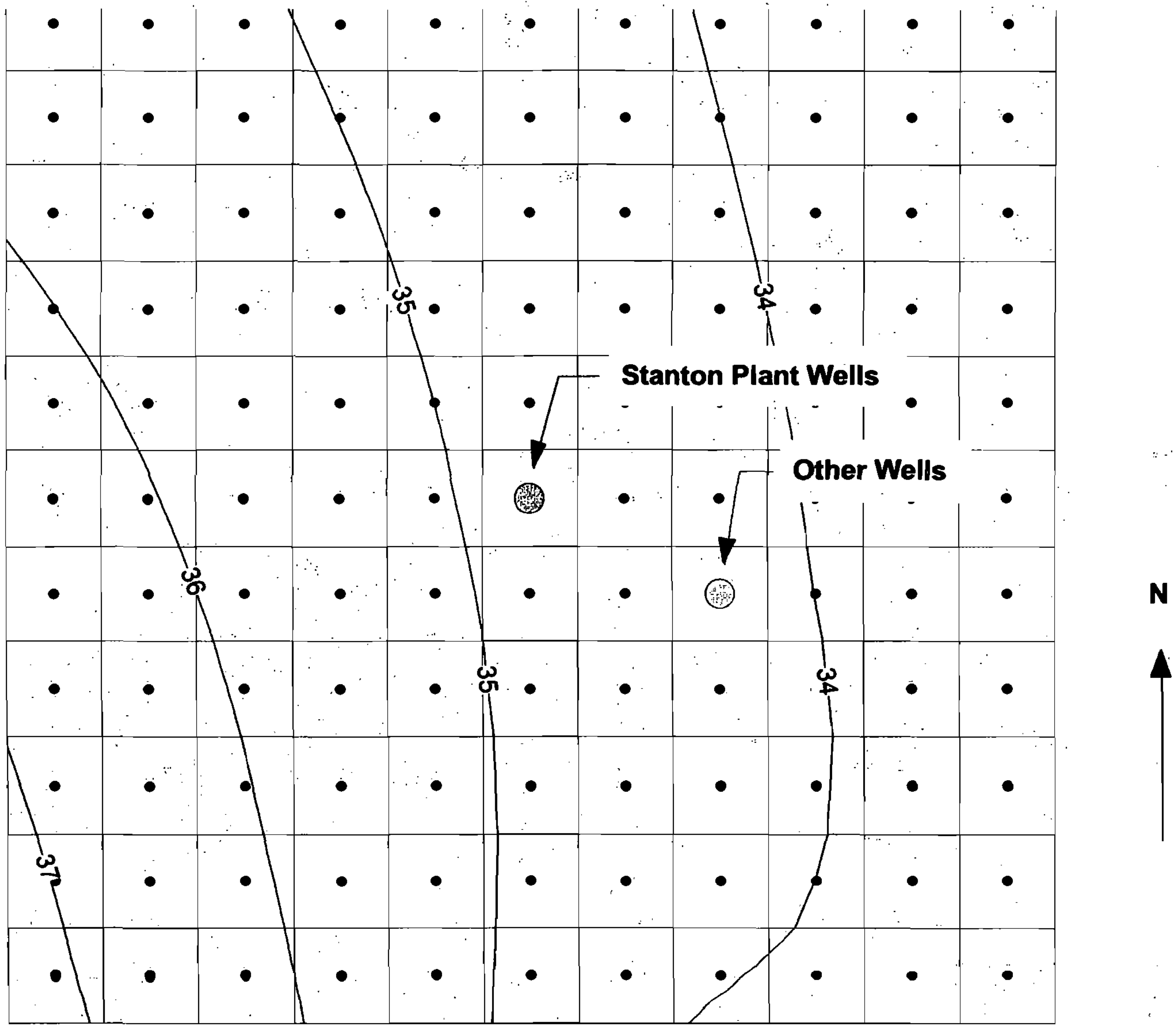
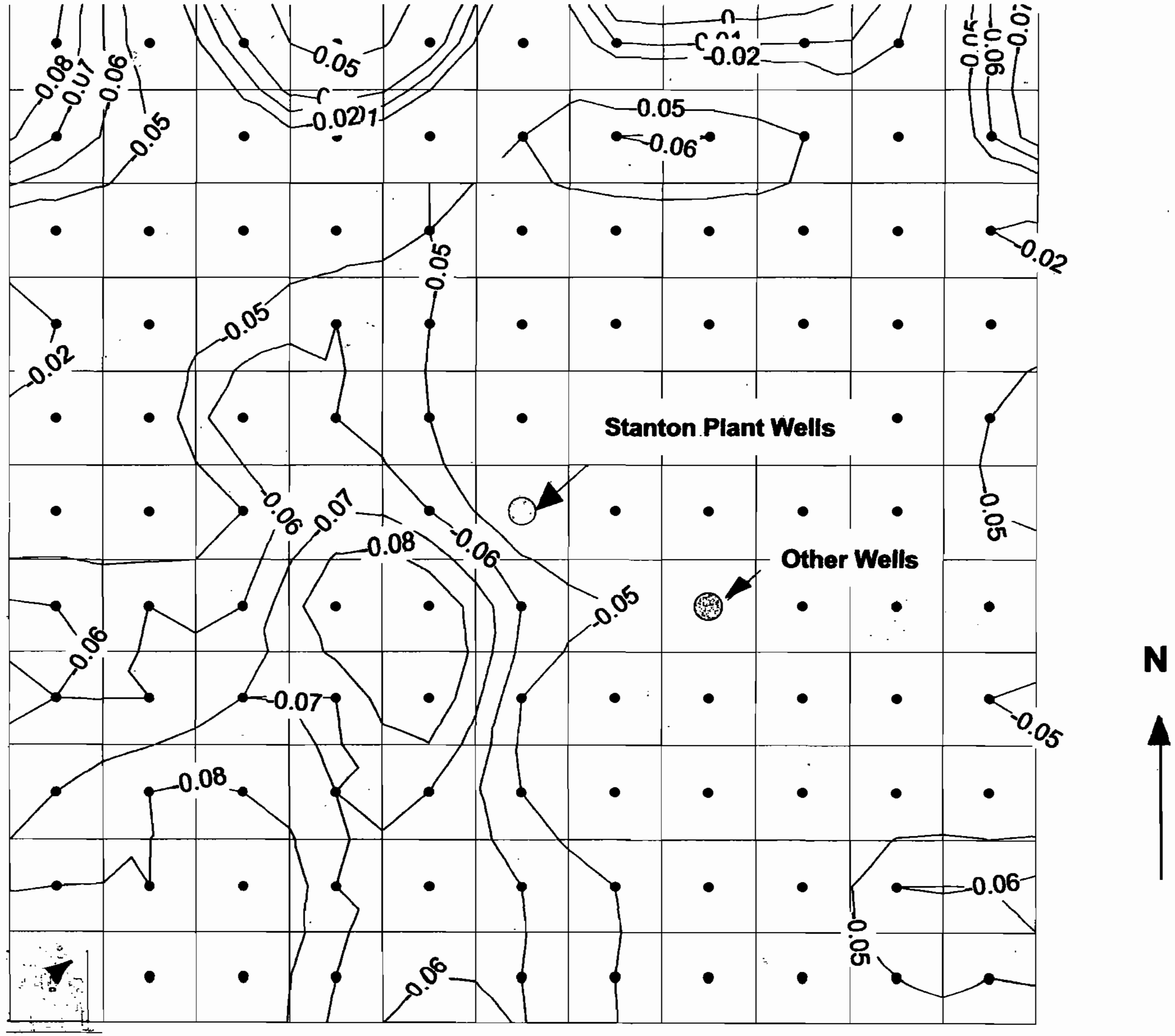
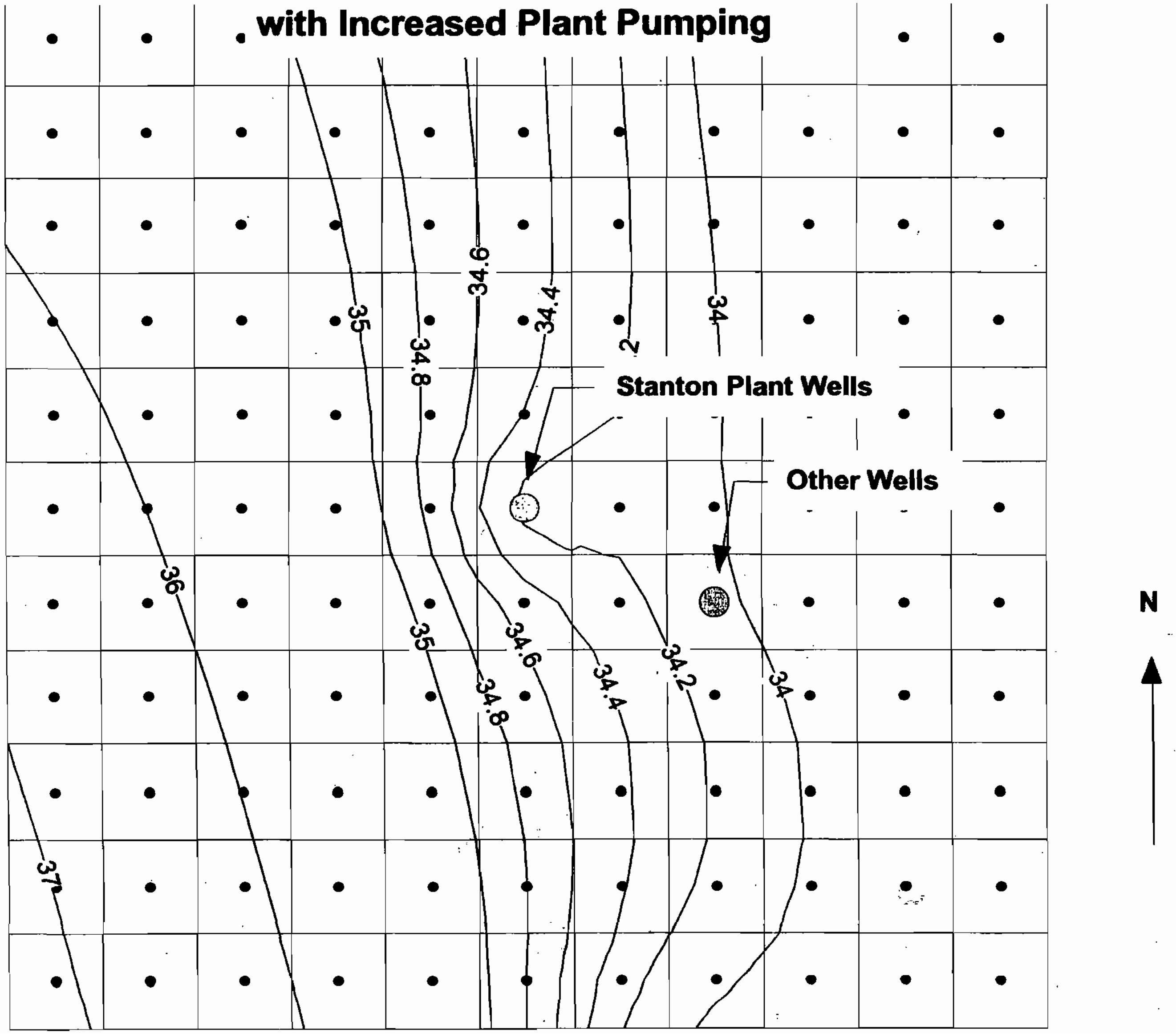


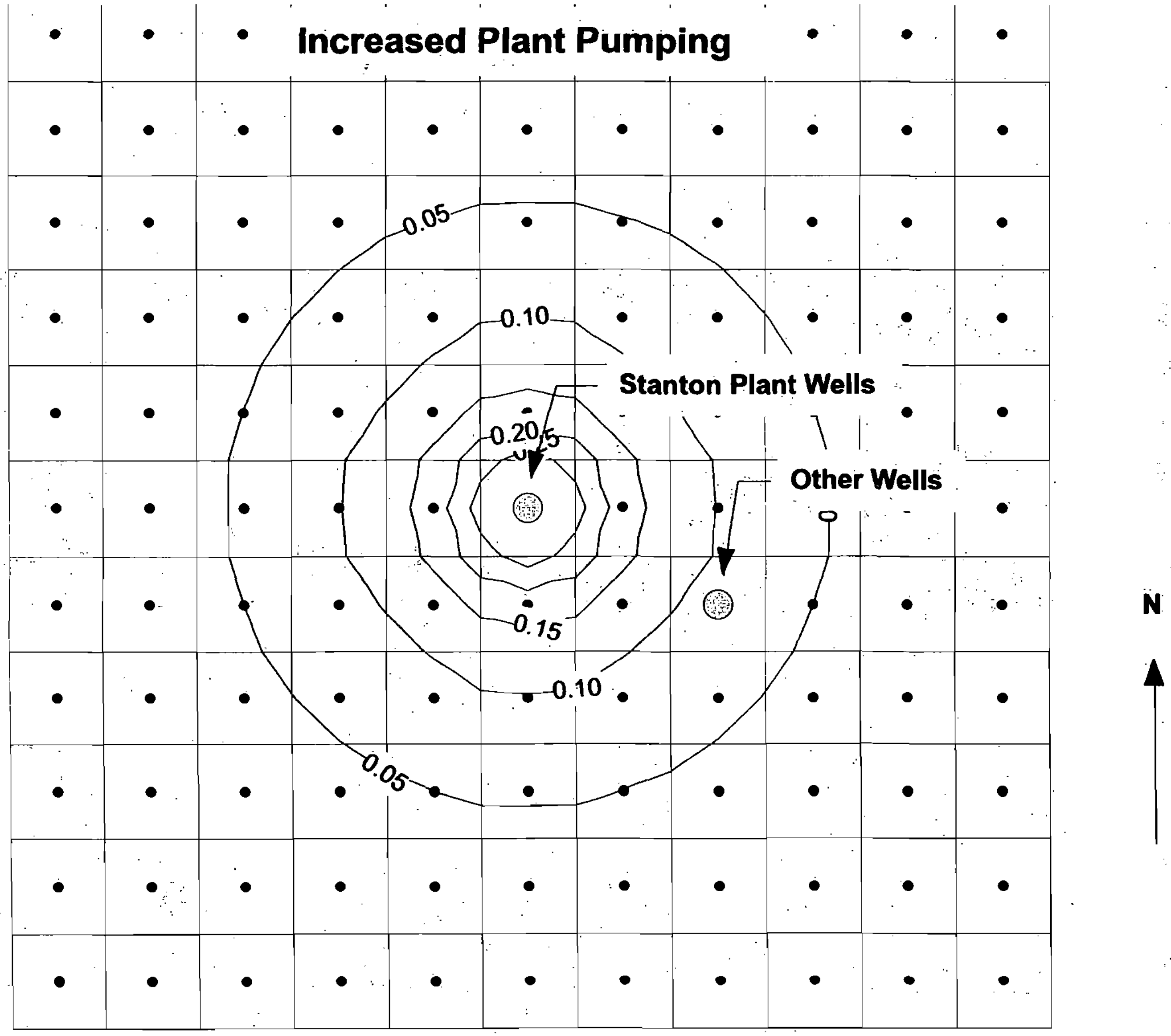
**Figure 7: 2020 and 1995 SAS (Unconfined Aquifer) Water Table Elevation Differences**



## Figure 8: Potentiometric Contours for the Upper Floridan Aquifer with Increased Plant Pumping



## Figure 9: Increase in Drawdown in the Upper Floridan Aquifer Due to Increased Plant Pumping



# SOURCES OF WATER
(Summary Data Sheet)

Please supply information regarding the source(s) of water for your activities. Include information regarding **all** wells/pumps on the property.

Table 1.
## SUMMARY OF GROUND WATER SOURCES

| Well or Pump Number | Wellfield or Facility Name | Casing Dia. (in) | Casing Depth (ft) | Total Depth (ft) | Operation Hrs/wk | Pump Capacity (in gpm) | Date Drilled | Existing or proposed (date) | Type of Use* |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Stanton | | | | 84[1] | 850 | | Existing | (d) |
| 2 | Stanton | | | | 84[1] | 850 | | Existing | (d) |
| | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | |

1 One continuous, one spare
* - See use descriptions on page 4. If more than one use type, show predominate use

Table 2
## SUMMARY OF SURFACE WATER SOURCES

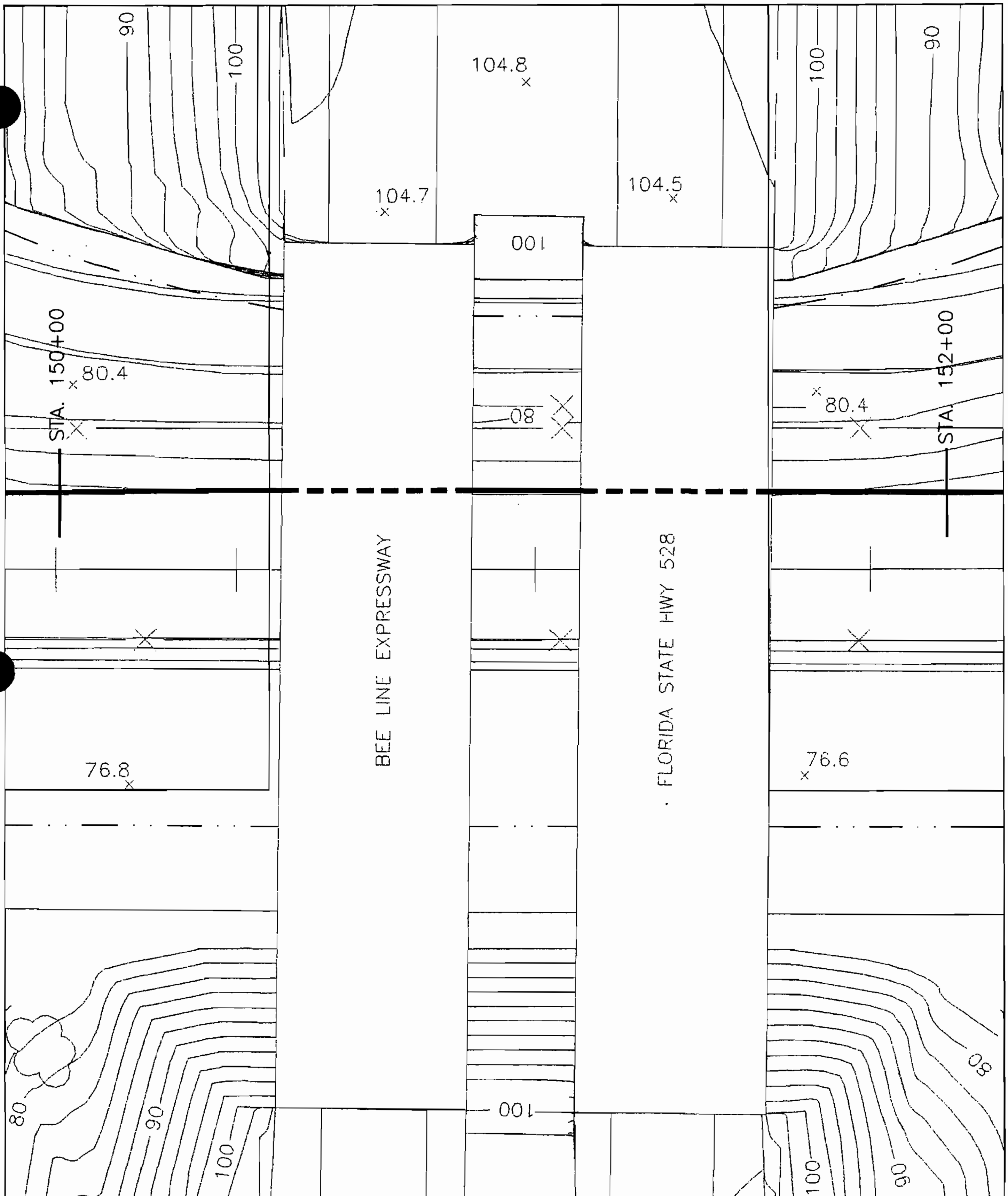
| Pump Number | Pump Capacity (gpm) | Operation Hrs/wk | Acreage of Surface Water Body | Name of Source | Status (date if proposed) | Type of Use |
|---|---|---|---|---|---|---|
| 1HRD-P-1A | 4500 | 84[1] | 93 acres | Makeup Wtr Supply Storage Pond | Existing | (d) |
| 1HRD-P-1B | 4500 | 84[1] | 93 acres | Makeup Wtr Supply Storage Pond | Existing | (d) |
| 1WSG-P-1A | 1150 | 84[1] | 15 acres | Recycle Basin | Existing | (d) |
| 1WSG-P-1B | 1150 | 84[1] | 15 acres | Recycle Basin | Existing | (d) |

1 One continuous, one spare

## Florida Department of Transportation

*The Florida Department of Transportation (Department) has reviewed the subject application for the site certification and found that additional information will be needed for the Department to adequately evaluate the application for certification. The Department will need detailed construction plans for the natural gas pipeline's crossing of State Road 528 and its right of way.*

**Response:** Preliminary construction plans for the natural gas pipeline's crossing of State Road 528 and its right of way are attached. The plans comply with the Department's Utility Accommodation Manual. The plans have been provided to Mr. George Marek of the DOT's District 5 Maintenance Office.




**LEGEND**

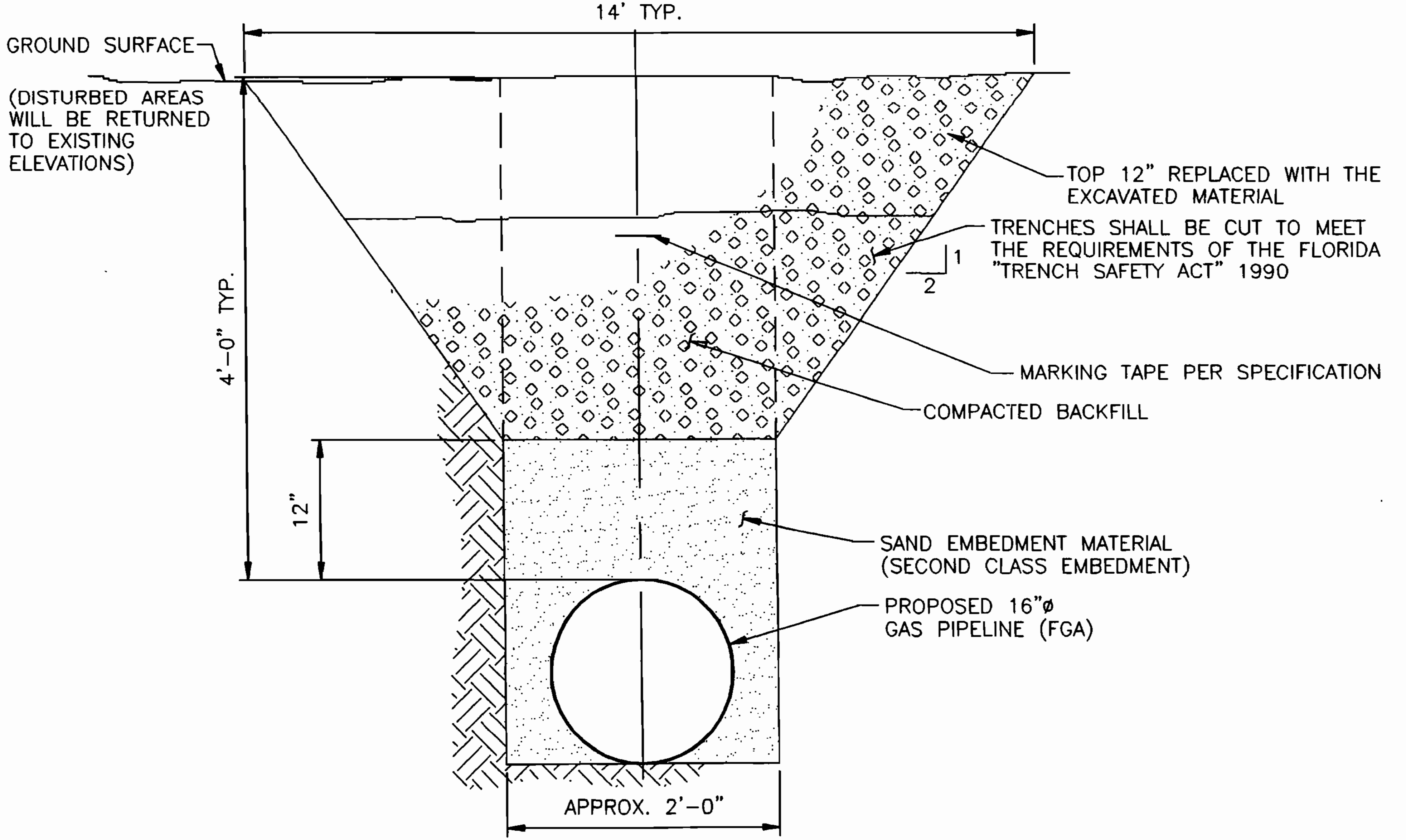
16" GAS PIPELINE

SILT FENCE
(TEMPORARY WORK AREA)

30' 20' 10' 0 30' 60'

1"=30'

SEC COMBINED CYCLE UNIT A
PIPING UNDER BEE-LINE EXPRESSWAY




LEGEND

SAND EMBEDMENT

EXISTING SOIL

COMPACTED BACKFILL

12" 6" 0 1' 2' 3' 4' 5'

1/2"=1'-0"

**TYPICAL GAS LINE TRENCH EXCAVATION**
**FIGURE 6.2-2 (04-17-2001)**

# Department of Environmental Protection

FLORIDA

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

March 12, 2001

Mr. Fredrick F. Haddad, Jr., P.E.
Vice President, Power Resources
Orlando Utilities Commission
Post Office Box 3193
Orlando, Florida 32802

Re: Stanton Energy Center combined Cycle Unit A, PA 81-14SA2

Dear Mr. Haddad:

The Department of Environmental Protection and other affected agencies have reviewed the Supplemental Site Certification Application submitted on January 22, 2001. The Department finds the application to be not sufficient. Please provide information requested in the following comments:

AIR

1. The emission limits proposed within the application are based upon the premise that for every hour of the year the unit will be operating with either duct burners firing, in power augmentation mode or firing fuel oil. Based upon its extensive history of permitting combustion turbines during the past 2-years, the Department does not find this to be reasonable for the determination of permit limits. An allotment of hours for each off-normal mode of operation will be assigned, which is consistent with prior BACT determinations.
2. The application requests emission limits of CO to be set in lb/hr rather than concentration limits. The Department evaluates BACT for CO based upon concentration rather than mass emission rates, and assigns permit limits in the same fashion.
3. Please confirm the Department's interpretation of the following CO emissions at 100% CT output:

| **Case** | **Operating Mode** | **ppmvd @ 15%$O_2$** | **pounds per hour** |
|---|---|---|---|
| 1 | CT operating at 19 degrees F | 7.4 | 31.0 |
| 13 | CT with cooling (EC) and duct burners (DB) at 70 degrees F | 18.1 | 87.51 |
| 18 | CT with EC, DB and power augmentation at 95 degrees F | 27.9 | 142.51 |

| | | | |
|---|---|---|---|
| 20 | CT on oil at 19 degrees F | 14.7 | 71.0 |

4. Please explain the Oxidation Catalyst economic analysis with regard to emissions reductions. According to the Air Construction application form (page 22) maximum requested annual CO emissions are up to 448.12 TPY (gas firing). Considering that the CO emissions resulting from an oxidation catalyst are 74.7 TPY, an emission reduction of 373.42 TPY should be evaluated rather than 319.7 TPY.

5. Based upon the requested permit levels of CO and related submittals, the application appears to support the installation of an oxidation catalyst. However, the Department wishes to point out that recent tests from TECO's Polk Power Station 7FA resulted in CO emissions of less than 1 ppmvd (gas) and less than 2 ppmvd (oil) at full load. Although contracting for CO limits between GE and its customers may not have caught up with field experience, actual results should be considered in the setting of BACT.

6. The applicant should be advised that ammonia slip is currently being permitted at 5 ppmvd.

7. Please indicate the maximum gross MW capability of the combined cycle unit, and under what operating conditions this output is achieved. Please provide the same information for the maximum heat input of the CT's and the gas-fired duct burners under ISO conditions. Maximum combined heat input rates have been specified for non-ISO conditions at 2402.0 MMBtu/hr firing natural gas (Case 4 while firing duct burners) and 2067.6 MMBtu/hr oil firing (Case 20).

8. Please provide the estimated time frames required, estimated number of annual start-ups and the estimated emission levels of $NO_X$, CO and PM/$PM_{10}$ during hot and cold start-up periods. The Department intends to define these levels in the setting of BACT.

9. The Department requires as a submittal, a project specific, written cost estimate of a $SCONO_X$ control system, to be supplied by the technology provider (Alstom Power). In addition to capital cost requirements, the submittal should include vendor estimates for use in determining any applicable annualized operating and maintenance costs.

10. Each economic analyses should be revised to incorporate the information specified above as well as the utilization of OAQPS Control Cost Method factors (e.g. contingency). Additionally, according to the application's Section 4.6.7.2, lost revenues are included in the annualized cost estimate. These should be excluded from the analyses.

WATER

The following are Industrial Wastewater Review Comments:

1. The applicant has provided a single line diagram for the new expansion. This diagram does not show chemical feeds and all treatment systems. Some existing treatment units will be used for the treatment of the wastewater generated from the new expansion. A revised single

line diagram for the entire facility (Units 1, 2 and A) showing all treatments units, chemical feeds, and disposal methods is requested. Please show average daily and maximum daily flows for all existing units and the expansion.

2. On figure 3-5-1(single line diagram), please show final disposition of the treated water and wastewater for "OUC Tower Blowdown Treatment System" (node 60)

3. Please provide details of the SEC Recycle System. What is the make up of the basin structure?

4. Section 3-6 (page 3-13) – Please show the new brine concentrator system on the single line diagram. Also provide details of the boiler cleaning waste neutralization system. Where doe the cleaning waste disposed of.

5. 3-6-6 – Please provide details of the neutralization basin. Show all incidental waste stream and flow volumes from existing and the new units.

6. 5-2-1 Oil and Grease concentration of the water discharged from the transformer enclosure will be at 10.0mg/L. The discharge concentration is limited at 5.0mg/L. If the contamination is due to petroleum based oils, the Department will suggest sampling for TRPH (Total Residual Petroleum Hydrocarbons). The limit for the TRPH concentration in the effluent remains at 5.0 mg/L. The Department may require effluent monitoring for this discharge. Please provide details of the disposal area.

7. Projected Water Use on Page 5-28. It is indicated that the proposed expansion will require up to 2.91 mgd under normal operating condition. OUC should consider using up to 3 mgd available from Orange County Landfill located adjacent to OUC site.

8. This is referred to as a zero discharge facility. Zero must refer to surface water discharge because it does not appear to be an IW definition of zero discharge—unless the make-up pond is lined. Besides ground water and make-up well water, the make-up pond <u>may</u> receive any and all of the following:

    a. 2.9 MGD DW Effluent

    b. 0.369 MGD Effluent from Cooling Tower Blowdown Treatment System (effluent from crystallization system). This should probably be a good water quality but I do not see an analysis.

    c. 0.038 MGD From the boiler blowdown (The text states the blowdown water will be routed to the Stanton A cooling tower for reuse. Will it be "routed" though the make-up pond?)

    d. ? MGD From the gas desulfurization system (verbal information from GK in Air Section) that came from the Recycle Basin which receives:

    (1) 0.015 MGD effluent from an oil/water separator which receives wastewater from floor drains.

(2) 0.012 MGD effluent from R/O from the demineralizer

(3) wash down water

e. ? MGD There is also an ash system that receives Recycle Basin water but I am not sure if there is effluent and if it returns to this system.

If these waste streams go to the make-up pond, I would like these to be shown on a water balance even though the wastewater streams in the pond may be so diluted by the DW effluent and the ground water that there are no ground water quality problems.

9. Rainwater on Transformers is skimmed then water goes to stormwater pond. Is this tanks or IW?
10. The submittal said that they would complete Form 2CG for Industrial Waste application. I did not see it.
11. DW goes to a septic tank.
12. The quarterly data submitted uses a lot of "BDLs". The use is inconsistent. A parameter like Mercury will have a "<" for a couple of quarters then a "BDL" in the same quarter that other parameters have "<" symbols. Will ask for the lab sheets. If these detection limits are OK, we may be able to delete some parameters.
13. A considerable amount of waste is hauled. Who regulates the hauling?
14. Please provide copies of the chemistry laboratory bench sheets for the ground water monitoring data for the 14 monitoring wells for the years 1999 and 2000.
15. Some of the monitoring well information was missing for the 4th quarter of 2000. Were the wells dry? Please clarify.
16. The Central District does not have any record of the well completion information on the monitoring wells. Please provide copies of the Well Completion Report Forms for each monitoring well. If these forms were not included in the permit, please fill out copies of the attached forms and submit them to the Department with well construction diagrams.
17. Please revise the Water Balance (Figure 3.5-1) to include all of the wastewater streams going to the reuse basin and the make-up pond. Please show the recycle basin water going to Gas Desulfurization and Ash Systems and the return effluent if any.
18. Please sample the make-up pond, and the reuse basin for the parameters required in the quarterly ground water sampling plus TRPH.
19. For each wastestream in the expansion, please sample the correlative wastestream in the existing system for the parameters required in the quarterly ground water sampling plus TRPH.
20. Please provide a copy of an analysis of brine concentrator wastewater from a similar existing system. At a minimum the analysis shall include the primary standards for metals.

21. The scales for the monitoring well location maps are too small to accurately measure distances. Please show all of the monitoring wells on site plans with a scale similar to the Boring Location Map (Figure 2.3-4). Please include the locations of the Floridan Supply wells as well.

22. Please provide a scaled cross section through the reuse basin and the make-up pond.

23. If there are historic staff gauge readings for the ponds, please provide the data for 2000.

24. Please provide a data table for the monitoring wells which includes:

    a. Ground surface elevations.

    b. Top of casing elevations.

    c. Below top of casing depth for the years 1999 and 2000.

    d. Ground water elevations for the years 1999 and 2000.

25. Please be advised that currently the ground water is being monitored with the same parameters for both industrial waste streams and solid waste disposal sites. In reality, this is not necessary. Accordingly, based on the characterization of all industrial waste streams, please propose a separate Ground Water Monitoring Plan for addressing wastewater discharges into the reuse basin and the make-up pond.

    Please also be advised that a proposal for the revised Ground Water Monitoring Plan must include a provision of incorporating additional monitoring wells especially around the make-up pond as well as the reuse basin, along with appropriate parameters to be monitored in the ground water.

    It may also be noted that all new compliance monitoring wells shall be proposed not more than 100' form the discharge basin/ponds.

26. When the Site Certification is issued for the requested modification, the Ground Water Section, Central District, Orlando must receive one copy of Ground Water Monitoring reports for industrial wastewater discharges.

Environmental Resource Permitting

**1. Section 3.8.9 Stormwater Management System**

This section states that the system has been designed with a permanent pool residence time of 14 days. Since no littoral zone is proposed in the detention pond design a minimum 21-day residence is required per 40C42.026(4) F.A.C. Please provide supporting calculations

This section states that the system has been designed to attenuate the peak discharge from the 100-year - 24 hour storm. Please provide a pre-post demonstration for the 25 year/ 24 hour and Mean annual (2.3) year / 24 hour design storms using the SCS II (Florida Modified) Rainfall Distribution. The 25-year storm is the design storm for projects within the SJRWMD and the Mean annual storm is required for projects within the Econ Basin. Please provide inputs and output for any routing runs used in the demonstration.

a. Please provide stage storage calculations with indicated levels and associated volume for permanent pool as well as pollution abatement levels.

b. Please provide a recovery demonstration indication the orifice meets the bleed down requirements in 40C-42.026(4)(b).

2. Section 2.3.3 Vegetation

This section describes the types of common plants found and animals observed in SEC's entire parcel (excess of 3, 000 acres). However the report does not specifically address the vegetation and animals found with the 60 acre expansion site for Stanton A, or within the proposed Substation, utilizing the Natural Gas Pipeline and for the Transmission line. In addition, the report references a botanical survey conducted from 1980 to 1981. Please provide more recent data for the site.

3. Section 3.3.3.2 mentions that the existing rail line will be upgraded northwest of the coal units. What does the upgrade entail to the rail line? Addition impacts to wetlands, additional impervious stormwater concerns, etc?

4. Please provide the Central District with a copy of the Orlando Utilities Commission Joint Agency Mitigation Monitoring Plan (1992).

5. Section 4.1.1 identifies General Construction Impacts

The 60 acre Stanton A is described as "generally maintained grassland". This is not sufficient information/description to conclude that the area is an upland. Please clarify and revise accordingly.

a. Please provide a copy of the wetland determination for this parcel.

b. Was a formal binding determination permitted by the Department? If yes, please provide a copy.

c. Specifically identify all wetland areas proposed for impact, (including temporary and permanent and for the conversion of a forested system to a herbaceous wetland).

6. Drawing Figure 6.1-1 is not legible.

7. Please provide clear detailed plan and cross section drawings to the proposed transmission line. Specifically include:
    a) road names
    b) location of existing line (with dimensions)
    c) location of proposed line (with dimensions)
    d) location of wetlands, ditches, surface waters, etc (in numerical order)
    e) length and width of the line that will impact wetlands
    f) legend for wetlands including type and acreage
    g) cross section location
    h) location of the proposed road
    i) substation location and dimensions
    j) concrete pad locations with dimensions
    k) turbidity barrier type and location
    l) Other pertinent information.

8. Revise the cross section drawings to provide:
    a) width of the line/corridor

b) Cross hatch fill in wetlands, surface waters, ditches, etc.
c) legend to the cross hatched areas
d) acreage to the impact areas
e) all dimensions to toe of slope
f) Dimension to slope to the keypad.

9. Demonstrate why a new 125 feet wide corridor is necessary for the proposed transmission line. Please provide avoidance/minimization and alternatives considered for the new line.

10. Section 6.1.8.1

a. Are culverts required to maintain hydrologic flow? If yes, please reflect on the plan and cross section drawings.

b. Where are the concrete foundations being installed? (Identify on the drawings any that will be in wetlands, ditches, surface waters, etc. and provide dimensions).

11. Section 6.1.8.4

Identifies 0.4 acres of forested cypress strand to be cleared. Table 6.1-3 indicates clearing will be permanent. Please identify whether the entire area will be converted from a forested wetland to a herbaceous wetland or from a forested wetland to upland filled area. Please revise the drawing and tables/exhibits accordingly.

12. 6.2 Natural Gas Pipeline

Where is the 4.5 mile 16 inch FGT transmission line located?

a. Demonstrate why a 16-inch pipeline requires a 50 feet wide permanent corridor.

b. Drawing Figure 6.2-1 may serve as an overall location map for the proposed natural gas pipeline provided road names and section, townships and ranges were added to the drawing and the drawing is legible.

c. Detailed plan and cross section drawings are required for the entire pipeline. Include in the plan view drawing:

a) wetland locations
b) wetland types
c) cross hatch proposed wetland impacts
d) location of the proposed pipeline
e) temporary work area with dimension
f) cross hatch wetland impacts
g) legend to the proposed wetland impacts
h) dimensions (length and width) to the impacts
i) road names
j) north arrow
k) Cross-section.

13. Cross-section drawing are necessary for the wetland, surface water and ditch crossings. Include the following:
    a) Identify cross section
    b) Width of cross section
    c) Cross hatch impacts
    d) Location of the existing railway, unimproved roadway, etc.
    e) Location of the transmission line
    f) Culvert type, size, dimensions, invert
    g) Stabilization type
    h) Turbidity type and location.

14. Please indicate avoidance/minimization considerations for the transmission line installation. Include documentation regarding the construction of this line by directional bore.

15. Provide a copy of the Permit file number, type of permit, date authorized for the existing 26 inch FGT gas line.

16. Will the pipeline cross any surface waters? If yes, please identify all surface waters in your drawings. Please note that if the surface waters are determined to be sovereign submerged lands than a public easement will be necessary for all sovereign impacts.

17. Section 6.3.7.2 states that the Green Branch and Turkey Creek will be crossed by the 16-inch natural gas transmission line. Has a title determination been conducted for these locations? Please note as indicated above that if these areas are sovereign submerged lands then a public easement with detailed survey drawings will be required for the impacts crossing any area that is sovereign.

18. Table 6.2.2 states fill in forested wetlands as a temporary impact. Please clarify. (Typically, the owner of the transmission line does not desire forested systems to recruit within their pipeline and corridor.)

Therefore, it appears that the fill in the forested system is a permanent impact. Please clarify and revise all documentation.

19. Section 6.2.7.3.1 references a survey conducted in 1981. These are outdated.

20. Section 6.2.8.4 states that the pipeline will have minimal impact on vegetation and is temporary in nature. Please refer to statement regarding permanent impacts above.

21. Figure 6.2-2 please revise to include the following to this exhibit:
    a) total width in wetlands
    b) Statement that all disturbed area will be returned to pre-existing elevations.

22. No detail plan view drawings were provided for the proposed pipeline.

a. Please note that it appears that mitigation will be required for the conversion of forested wetlands to a herbaceous wetland and for all permanent impacts.

b. What considerations were made for the Substation expansion which in the application reflects 0.13 acres of fill? Please demonstrate avoidance/minimization.

23. Please note that the drawings provided in the Joint Application for an Environmental Resource Permit application are not legible. (Refer to the questions/statements regarding the plan and cross section drawings above.)

24. ERP Drawing 98-362-ERP-4A reflects 2,760 square feet of wetland impacts to Wetland 5 (W5). Please explain why W5 impact (east of the existing roadway) is necessary.

25. The Section, Township and Ranges in the maps/drawings are not legible.

Also attached are requests for additional information from the St. Johns River Water Management District and the Florida Department of Transportation.

Sincerely,

Hamilton S. Oven

Hamilton S. Oven, P.E.
Administrator, Siting
Coordination Office

# St. Johns River Water Management District

Henry Dean, Executive Director • John R. Wehle, Assistant Executive Director

Post Office Box 1429 • Palatka, FL 32178-1429 • (904) 329-4500

March 2, 2001

DEPARTMENT OF
ENVIRONMENTAL PROTECTION

MAR 0 7 2001

ITING COORDINATION

Hamilton S. Oven, Administrator
DEP Siting Coordination Office
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, FL 32399-2400

Via Facsimile Transmission (850) 921-7250

Re: Curtis H. Stanton Energy Center Combined Cycle Unit A Power Plant Siting Supplemental Application No. PA 81-14SA2; DOAH Case No. 01-0416EPP; DEP Case No.01-0176; SJRWMD F.O.R. #2001-08

Dear Mr. Oven:

Pursuant to Section 403.5067, Florida Statutes, and Rule 62-17.081(2)(a)1, Florida Administrative Code, the St. Johns River Water Management District transmits to you its request for additional information which must be provided in order to render this application sufficient to enable the District to carry out its statutory responsibilities. The request below reflects the information the District's technical staff believes is needed to complete the District's review and to thereafter prepare a report to the Department:

1. District water use rules require that the lowest acceptable quality water source, including reclaimed water or surface water (which includes stormwater), must be utilized for each consumptive use. To use a higher quality water source an applicant must demonstrate that the use of all lower quality water sources will not be economically, environmentally or technologically feasible.

    a) A source of reclaimed water is readily available from the Orange County Easterly Waste Water Treatment System. Information submitted with the application indicates that this water is intended to be used for cooling uses, but not for all uses. Please demonstrate why it is not feasible to use reclaimed water for all uses except for potable water. In order to demonstrate that the use of a lower quality source is not economically feasible, the applicant must demonstrate in detail that the use would render the entire project economically unfeasible. [Section 10.3(e)(f)(g), Applicant's Handbook, Consumptive Uses of Water (February 8, 1999) (A.H.)]

b) A source of stormwater is available from the adjacent Orange County Landfill to meet some of the power plant's water needs. Please evaluate the feasibility of using this source. In order to demonstrate that the use of a lower quality source is not economically feasible, the applicant must demonstrate in detail that the use would render the entire project economically unfeasible. [Section 10.3(e)(f)(g), A.H.]

c) The application includes a request for 2.13 million gallons per day of groundwater from the Floridan aquifer for cooling water use during emergency conditions. The existing power plant facility includes an approximately 90-acre storage pond with approximately 146 million gallons of storage capacity. The Orange County Easterly Waste Water Facility has an emergency groundwater backup allocation of 100 million gallons per year. Orange County applied for renewal of this permit with the same allocation. That permit application is complete and will be recommended for approval. Please demonstrate why it is not feasible to use either the water in the existing storage pond or the emergency groundwater backup allocation for the Orange County Waster Water Facility for the requested emergency backup use. [Section 10.3(e)(f)(g), A.H.]

2. The applicant has completed an initial evaluation that includes simulations of the drawdown in the Floridan aquifer due to the average daily withdrawal from all three units and of the drawdown due to the maximum combined capacity of the onsite wells pumping continuously for 30 days. Please provide copies of the input and output files for these model simulations. Additional impact analyses are necessary as follows:

   - An analysis to evaluate the cumulative drawdown impacts of the proposed withdrawals in combination with withdrawals from all existing legal uses.

   - An analysis to evaluate the cumulative impacts of the proposed withdrawals in combination with withdrawals from all existing legal uses and all withdrawals requested by applicants whose applications are complete. This analysis is necessary to determine whether there are competing applications.

   - An analysis to evaluate the cumulative impacts due to all existing and reasonably anticipated uses at some future year or years, including the proposed withdrawals. This can be in multiple evaluations such as for years 2005, 2010 and 2020. The purpose of this evaluation is to address the sustainability of the resource.

   District staff can assist the applicant with the completion of these analyses. Doug Munch with the District's Division of Groundwater Programs may be contacted for further assistance at (386) 329-4173. [Sections 6.5.1; 9.4.1(b)(e)(f), 10.2(e)(f)(g)(k)(l)(p); 10.3(c)(d), A.H.]

3. Is any dewatering of the site anticipated to be required during construction? If so, please confirm that any site dewatering will be below the thresholds in section 40C-

22.030 of the Florida Administrative Code. [Sections 10.2 (e) (f) (g) (i); 10.3 (d) (i), A.H.]

4. The information requested for **all** wells and pumps/surface water sources located on the property must be included in the SOURCES OF WATER Summary Data Sheet. Please also provide information regarding any and all offsite sources (connection points) and surface water pumps associated with the onsite storage pond. [Form 40C-2-1082-1, A.H.]

The District appreciates the Department's assistance in obtaining the above-requested information. If further clarification is needed regarding the District's requests, please contact me at (386) 312-2347. Thank you in advance for your cooperation.

Sincerely,

Charles A. Lobdell, III
Assistant General Counsel

cc: James Hollingshead
Dwight Jenkins
Doug Munch

# *Florida Department of Transportation*

JEB BUSH
GOVERNOR

605 Suwannee Street
Tallahassee, Florida 32399-0450

THOMAS F. BARRY, JR.
SECRETARY


February 28, 2001

Mr. Hamilton S. Oven, P.E., Administrator
Siting Coordination Office
Division of Air Resources Management
Department of Environmental Protection
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

DEPARTMENT OF
ENVIRONMENTAL PROTECTION

MAR 02 2001

SITING COORDINATION

Re: Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Agency and Southern Company – Florida, LLC Curtis H. Stanton Energy Center Combine Cycle Unit A Power Plant Siting Supplemental Application
No. PA 81-14SA2
DOAH Case No. 01-0416 EPP
DEP OGC Case No. 01-0176

Dear Mr. Oven:

The Florida Department of Transportation (Department) has reviewed the subject application for site certification and found that additional information will be needed for the Department to adequately evaluate the application for certification. The Department will need detailed construction plans for the natural gas pipeline's crossing of State Road 528 and its right of way. Mr. George Marek of the Department's District 5 Maintenance Office will be pleased to work with the applicant to identify the details to be included in the plans. Mr. Marek can be reached by phone at (904) 943-5281.

If you have any questions, please call me at 414-5386 or Sandra Whitmire, Siting Coordinator, at 414-4812. Thank you.

Sincerely,

Sheauching Yu
Assistant General Counsel

cc: Roy Young and Tasha Buford, Esquires
David Bruce May, Jr. and Lawrence N. Curtin, Esquires
Brian Hutt, District 5
George Marek, District 5
Sandra Whitmire