SUPPLEMENTAL SITE CERTIFICATION APPLICATION

ORLANDO UTILITIES COMMISSION
CURTIS H. STANTON ENERGY CENTER
UNIT B IGCC PROJECT

SUFFICIENCY RESPONSES

Prepared for:

The Reliable One
Orlando, Florida

and

Energy to Serve Your World℠
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ORLANDO UTILITIES COMMISSION AND
SOUTHERN POWER COMPANY – ORLANDO GASIFICATION LLC
STANTON ENERGY CENTER UNIT B IGCC

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SUFFICIENCY RESPONSE

A. FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
Memorandum from Al Linero (FDEP) to Mike Halpin (FDEP),
Dated April 5, 2006

GASIFIER

***FDEP-1**—Please provide a copy of the key components of the technical proposal submitted to the Department of Energy for this project. We request a copy of the most recent scope of work that is under negotiation if not already approved. This will help us understand the constraints and the level of flexibility available to the applicant as we conduct our best available control technology (BACT) analysis. We can discuss with the applicant the details of this request prior to submittal including the treatment of confidential materials per applicable statutes.*

Response

The technical proposal has been superseded by the fully executed Cooperative Agreement between Southern Company Services (SCS) and the U.S. Department of Energy (DOE). The cooperative agreement has been designated as confidential with DOE. The components identified in the application are consistent with the Cooperative Agreement. The extent to which the applicant is constrained in its choice of particular components is noted in response to more specific requests herein. For example, the turbine manufacturer has been selected. Notably, the applicant does not believe the best available control technology (BACT) analysis should be affected by the component selected.

***FDEP-2**—According to available information, the pilot-scale KBR Transport Gasifier was tested at Wilsonville for air-blown and for oxygen-blown configurations. According to the SCA, an air-blown design will be demonstrated. Please provide the justification for selection of the air-blown variant and its impacts on emissions and emission control options. Include any information related to requirement, if any, for an air-blown version versus an oxygen-blown version to receive the DOE support. In the air-blown variations, the coal is introduced into the gasifier with compressed air. In the oxygen-blown variations, an air separation unit (ASU) is necessary to separate at-*

mospheric oxygen (O_2) from atmospheric nitrogen (N_2). Our interest in the air-blown versus oxygen-blown variations relates to the fact that in the air-blown version, atmospheric nitrogen (N_2) is carried through the entire gasification and cleanup steps. This may impact NO_x emissions.

Response

The overall objective of Stanton Unit B, from a DOE project perspective, is to design, construct, and operate an *air-blown* Transport Gasifier based advanced integrated gasification combine-cycle power plant that uses United States coal. SCS has conducted numerous evaluations of air-blown and oxygen-blown configurations that show air-blown to be the most economic and best performing alternative. Accordingly, an oxygen-blown system is not an option for this project.

In any event, the air-blown configuration is not expected to have any adverse impacts on nitrogen oxides (NO_x) formation. SCS's design studies have shown the NO_x emissions to be almost the same for either air- or oxygen-blown cases, with NO_x slightly less for the air-blown case. General Electric (GE) has explained that it is advantageous to have the nitrogen premixed with the fuel in regard to thermal NO_x formation in the combustion turbine (CT). In other words, carrying the nitrogen through the gasification process operates similarly with respect to thermal NO_x formation to the reintroduction of nitrogen prior to combustion in an oxygen-blown system.

Stanton Unit B will utilize a sub-bituminous Powder River Basin (PRB) coal—a low-rank, high-moisture, high-ash coal. Because low-rank, high-moisture, and high-ash coals comprise approximately half the proven coal reserves in the United States and the world, utilization of these coals for power generation is an essential component of United States energy policy. Currently employed integrated gasification combined-cycle (IGCC) technologies use high-rank fuels and are not competitive economically for operation with low-rank fuels. A recent Electric Power Research Institute (EPRI) report discussed the effect of coal quality on coal plant economic feasibility and published the figure below showing the impact of coal rank on the relative heat rates and capital cost of pulverized coal (PC) plants and IGCC plants. The report stated, "This illustrates the widening gap for lower rank coals, particularly for slurry-fed gasifiers, such as ChevronTexaco (now owned by GE) or ConocoPhillips. This reinforces the need for development of improved gasifiers, such as the KBR Transport Gasifier, for low-rank coals."

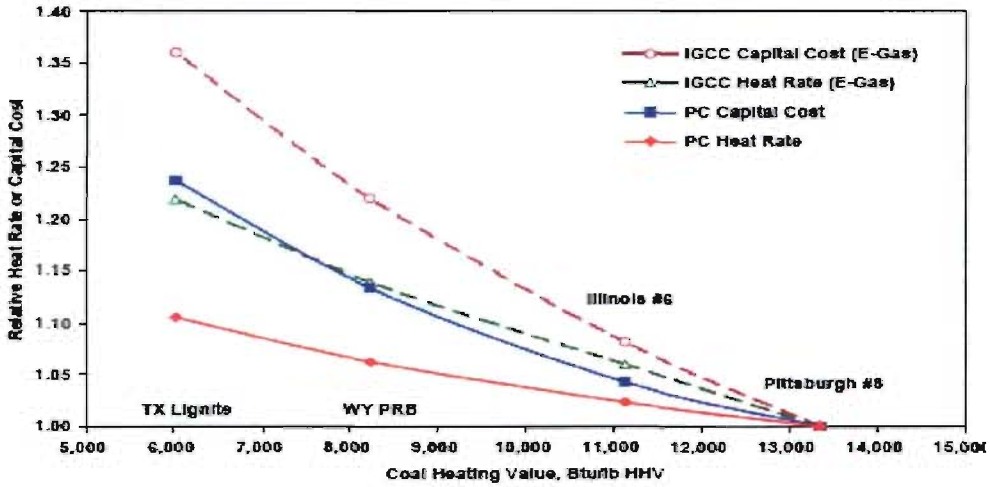


Figure 6-2
Effect of Coal Quality on Heat Rate and Capital Cost

Source: EPRI, 2004, Gasification Technology Status, Report #1009769.

Although some proposed future IGCC plants include the technical flexibility to process sub-bituminous coals, economic estimates using these technologies with sub-bituminous coal compare unfavorably to bituminous coal. While all gasifiers can process low-rank sub-bituminous coals, not all gasifiers can perform as well economically as the air-blown Transport Gasifier. Economic studies performed by EPRI and by SCS in conjunction with DOE, indicate that the Transport Gasifier is an economically promising option.

In any event, the choice of air-blown or oxygen blown is a fundamental design feature that the applicant does not believe can be the subject of the BACT analysis.

FDEP-3*—Were varying degrees of air-blown and oxygen-blown considered that could help reduce the volume of syngas while providing a specific N_2 stream for direct injection into the combustors or for coal handling? If so, please describe and submit any documents pertaining to this issue. SCR is proposed by the applicant to reduce NO_x emissions from 40 to the range of 12 to 20 ppmvd @15% O_2. The values would still be greater than the reference oxygen-blown IGCC plants available from GE and Conoco-Phillips consortia (with SCR). For reference, the 220 MW (net) air-blown Nakoso IGCC project is under construction and will start up in 2007. The process used is, like the present application, also aimed at lower rank coals. Mitsubishi Heavy Industries (MHI) has single point responsibility for the sponsoring consor-

tium and is the main supplier for (at least) the gasifier, combustion turbine, heat recovery steam generator (HRSG) and SCR system. The SO_2 and NO_x targets for this demonstration project are 8 and 5 ppm @16% O_2. This suggests the possibility of a CT/SCR combination capable of achieving very low NO_x values for an air-blown configuration (and possibly for the air-blown KBR Transport Gasifier as well).

Response

Varying degrees of air-blown and oxygen-blown configurations were not considered. As noted in the response to FDEP-2, Stanton Unit B has been proposed as an air-blown IGCC. SCS's design studies have shown the NO_x emissions to be almost the same for either air- or oxygen-blown cases, with NO_x slightly *less* for the air-blown case. GE has explained that it is advantageous to have the nitrogen premixed with the fuel in regard to thermal NO_x formation in the CT.

Regarding the "reference plant" designs mentioned above and their claims for low emission rates, it is important to note that:

- These are different types of gasification technologies using different fuels and thus constitute different source types from Stanton Unit B.
- None of these "reference plant" technologies or low emissions rates have been demonstrated in practice.
- Recently permitted IGCC projects using these reference plant technologies have not been permitted at these claimed levels, nor have proposed projects proposed emission rates at these levels.

The Nakoso IGCC project is similar in technology to Stanton Unit B only in that it is proposed as air-blown gasification aimed at low-rank fuels. Like Stanton Unit B it is a demonstration project with low emissions targets. Low emission rates are also the target of Stanton Unit B. It is to the Unit B project's advantage to drive emissions as low as possible. Stanton Unit B, however, must also serve reliably as a base loaded power generation unit serving the retail customers of Orlando Utilities Commission (OUC). Lower reliability, forced outages, or increased maintenance outages are unacceptable and are not consistent with the goals of the Clean Coal Power Initiative (CCPI) program. The two-phase

NO_x limit proposed for Stanton Unit B achieves two major milestones in IGCC technology advancement in the United States:

- Employs selective catalytic reduction (SCR) control technology for the first time on a coal-based IGCC facility.
- Establishes the lowest NO_x limit to date for an IGCC facility.

NO_x CONTROL

***FDEP-4**—The comment is made on Page 5-31 that the CT manufacturer has issued a guarantee of 40 ppmvd NO_x @15% O_2 (prior to additional control). Please advise whether a contractual obligation exists to purchase the specific General Electric F-Class CT that forms the basis of the applicant's Best Available Control Technology (BACT) proposal.*

Response

The contract for the CT equipment, engineering and testing was signed with GE on February 22, 2006. The guarantees referenced on page 5-31 are taken from the contract documents. The contract signing obligated Southern Power Company – Orlando Gasification LLC (SPC-OG), to make monthly payments as per the terms of the CT contract. The applicant has requested a permit for construction of the referenced turbine.

***FDEP-5**—Provide a copy of relevant portions of the guarantee and related information, particularly the assumptions made for the syngas stream characteristics that presumably form the basis of the guarantee. The guaranteed NO_x value for syngas combustion submitted in the application seems high. Advise whether or not the manufacturer or model of the CT is set by conditions of the DOE award in the same manner that the gasifier has been specified.*

Response

The entire CT contract has been designated by the vendor as *Proprietary Information*. Therefore, SPC-OG cannot provide the documentation requested from the contract. However, the attached table presents the information that formed the basis of the guarantee.

The applicant was not limited to a certain manufacturer and/or model of CT by DOE award; however, the selected turbine formed the basis of the applicant's proposal to

DOE. The selected vendor was the only one offering a complete set of guarantees for syngas operation. The response to FDEP-6 describes review of offers from other manufacturers. Prior to its execution, the CT contract with GE was approved by DOE. Regardless, the selected turbine is the basis of the Prevention of Significant Deterioration (PSD) permit application submitted by the applicant.

<u>FDEP-6</u>—Please advise what other large frame combustion turbines capable of combusting syngas were considered prior to the decision to commit to the selected model. Advise what NO_x guarantees these other manufacturers could provide and the syngas constituents upon which they based their proposal.

Based on Department research to date, it appears the proposed project should be able to meet 2.0 ppmvd NO_x @15% O_2 on a 24-hr basis when burning natural gas based on the proposed guarantee of 25 ppmvd @15% O_2. This value is equal to the recent draft BACT determinations made for the FPL West County Project (G-Class), the draft BACT determination for the FMPA Treasure Coast Project (F-Class), and the final BACT determination for the FPL Turkey Point Unit 5 Project (F-Class).

A 343 MW (net) vacuum residuum (VR)-fueled oxygen-blown IGCC plant started up at the NPC Negishi Refinery in 2003. VR is basically petcoke (prior to coking). The project has an MHI F-Class combustion turbine as well as MHI SCR system to achieve 2 ppmvd @16% O_2. MHI is apparently able to achieve very low NO_x values for the VR-fueled Negishi IGCC project.

In addition, the 300 MW (net) ELCOGAS and 253 MW (net) Buggenum oxygen-blown IGCC plants in Europe practice introduction of an N_2 stream from the ASU with the syngas prior to combustion in Siemens 94.3 and 94.2 CTs. This is in contrast to the oxygen-blown TECO Polk Power Station where the N_2 is apparently introduced into the CT separately from the syngas. The cleaned and diluted (by N_2) syngas arriving to the CTs used at the European projects is similar in key constituents and heating value to the cleaned syngas expected from the proposed air-blown KBR Transport Gasifier process. It should be possible to achieve the same relatively low NO_x emissions achieved by the older (by 10+ years) ELCOGAS, Buggenum, and TECO demonstration projects prior to further control by SCR.

<u>Response</u>

Concerning other CT technology suppliers for syngas operation, SPC-OG also reviewed proposals submitted from Siemens and Mitsubishi. All were evaluated for initial cost, performance and life-cycle costs. GE was evaluated to have the best and most complete proposal of the group. GE was the only supplier offering a full set of guarantees.

Regarding the operation of Stanton Unit B on natural gas, a NO_x emission limit of 5 parts per million (ppm) has been proposed. This is based on use of SCR and a CT emission rate of 25 ppm, utilizing a diffusion flame combustion system (the only burner type capable of combusting syngas). This presumes an SCR removal efficiency of 80 percent. The referenced Florida CT projects, all of which use dry low-NO_x burners, have estimated SCR removal efficiencies that range from 78 to 86 percent. Accordingly the proposed limit for Stanton B is consistent with the control technology applied to these other Florida projects.

The Negishi IGCC is a different gasification technology and uses a different fuel from Stanton Unit B. Little information is available as to the Negishi plant's turbine exhaust characteristics, inlet concentrations, and SCR removal efficiency or enforceable permit limits. This unit is not directly comparable to Unit B.

The Florida Department of Environmental Protection's (FDEP's) comments regarding NO_x emissions from syngas-fired CTs do not account for the impact on NO_x emissions of inherently higher fuel-bound nitrogen resulting from gasification of sub-bituminous fuel. To date, all commercial coal-fired IGCC plants have used high-rank bituminous coals. The proposed Unit B project, however, will demonstrate use of low-rank sub-bituminous coals. The introduction of nitrogen described previously primarily affects the formation of thermal NO_x, not fuel NO_x. Thermal NO_x formation in the Unit B CT should be similar to that of other IGCC units.

FDEP-7—Has consideration been given to a combination of pre-combustion catalytic conversion of the NH_3 (still remaining in the syngas after ammonia recovery) to N_2 then post-combustion SCR? There could be an economic/technical optimum. Has consideration been given to partial oxidation of remaining NH_3 in a staged CT combustor to convert it to N_2, then completing the combustion at temperature lower than thermal NO_x formation temperature?

Response

Catalytic conversion of ammonia in the syngas is not technically feasible. Catalytic conversion of ammonia in syngas is an experimental process that requires high temperatures of around 1,600 degrees Fahrenheit (°F) to minimize catalyst deactivation from other species in syngas. For the projected syngas composition, the concentration of ammonia after recovery is well below the theromodynamic equilibrium concentration for the decomposition reaction. Consequently, attempting to reheat the syngas for catalytic conversion at this stage would not decrease ammonia concentration.

Regarding staged combustion, GE has stated to FDEP that a two-stage combustor is not technically available for syngas applications, and currently only the multinozzle quiet combustor (MNQC) can be used.

***FDEP-8*—The GE F-Class CT (basically similar to the GE F-Class model selected for the present project) consistently achieved 15 to 20 ppmvd NO_x (without SCR or steam saturation) at the oxygen-blown TECO Polk Power Station IGCC demonstration project. This was accomplished by reinjection of the N_2 stream from the ASU to the combustors. Please explain if and why (in the proposed air-blown project) carrying the N_2 through syngas production, cleanup and combustion causes more NO_x production or a greater NO_x emission guarantee. In either case, all the syngas and N_2 ultimately occupy the combustor and would appear to have equal NO_x formation potential.**

Response

The introduction of nitrogen described above primarily affects the formation of thermal NO_x, not fuel NO_x. Because the turbine technology proposed for Stanton Unit B will be very similar to Polk Power Station, no significant difference in thermal NO_x is expected. As mentioned previously in the response to FDEP-2, SCS's design studies have shown the NO_x emissions with respect to PRB coal gasification are approximately the same for either air- or oxygen-blown cases, with NO_x slightly less for the air-blown case. Higher ammonia (NH_3) and hydrogen cyanide (HCN) concentrations and fuel NO_x emissions are expected for sub-bituminous coal-derived syngas since more ammonia and HCN is typically formed from sub-bituminous coal than from bituminous coal.

***FDEP-9*—The TECO project was subsequently modified to include steam saturation of the syngas (not the same as steam diluent injection). When combined with N_2 diluent injection NO_x concentrations on the order of 10 ppmvd @15% O_2 are realized. Please advise whether or not the steam saturation principle, or some other catalyst/control pre-SCR and pre-CT, can be applied to the proposed project to some extent in order to further reduce NO_x emissions prior to further control by SCR.**

Response

Steam saturation (or a similar process) cannot be applied. According to the turbine vendor, the projected heating value of the Unit B syngas is too low to be further reduced by steam saturation prior to combustion.

***FDEP-10*—Provide the average cost-effectiveness of NO_x removal from 40/25 to 10/2 and to 5/2 ppmvd @15% O_2 when using syngas/natural gas. Assume in these cases that fouling by ammonium/sulfate compounds is not significant.**

Response

As discussed in Section 5.4 of the PSD permit application (BACT Analysis for NO_x), a key objective of the Unit B DOE demonstration project is to assess the viability of the presently unproven application of SCR control technology to syngas-fired combined-cycle CTs. For the reasons stated in Section 5.4, SCR is presently not considered "technically feasible" for purposes of BACT and does not represent BACT for this project while firing syngas. Accordingly, SCR NO_x removal cost-effectiveness data were not provided for syngas operation.

SCR operation during natural gas operation is necessarily defined by operation of the SCR as designed to accommodate syngas. Accordingly, it is also not technically feasible to design an SCR system based solely on natural gas operation. The applicant has proposed the maximum control for NO_x when operating on natural gas that is considered technically feasible given the requirement to treat exhaust streams resulting from both syngas and natural gas combustion. Therefore, SCR NO_x removal costs for natural gas operations were not provided.

SO_2 CONTROL

***FDEP-11**—Both GE and Conoco-Phillips offer very low NO_x limits for IGCC projects in conjunction with deep sulfur removal equivalent to an emission rate of 0.01 lb SO_2/mmBTU. The present applicant proposes to use low sulfur Powder River Basin (PRB) coal and achieve deep sulfur removal to a proposed limit of 0.015 lb SO_2/mmBtu. Please advise the additional cost to further reduce SO_2 emissions thus avoiding the claimed limitations to NO_x control by SCR and the interactions by the applicant between NH_3 slip and SO_2.*

Response

The applicant has proposed the maximum control for sulfur dioxide (SO_2) that is considered "technically feasible" for purposes of BACT. The proposed Unit B SO_2 BACT emission limit of 0.015 pound per million British thermal units (lb/MMBtu) is well below the SO_2 limits established as BACT for all currently permitted IGCC facilities (i.e., more than 10 times lower). The SO_2 BACT limit proposed for Unit B is also well below all recently proposed and permitted coal-fired projects. The Unit B proposed SO_2 emission limit is therefore considered to represent the "top alternative" in the top-down SO_2 BACT analysis. Accordingly, cost-effectiveness data were not provided for the Unit B SO_2 BACT analysis. The SO_2 emission rate referenced has not been demonstrated, permitted, or commercially guaranteed.

***FDEP-12**—Please provide an estimate on the breakpoint when sulfur in the syngas actually becomes a problem. On the one hand, the claim is made that virtually any sulfur presents a problem. On the other hand, GE seems to believe that 0.01 lb SO_2/mmBtu is acceptable for its oxygen-blown gasifier design while achieving very low NO_x emissions. Note that with the great head-start from low sulfur PRB coal this issue will not be as difficult as it is for high sulfur Eastern coal IGCC plants for which GE developed.*

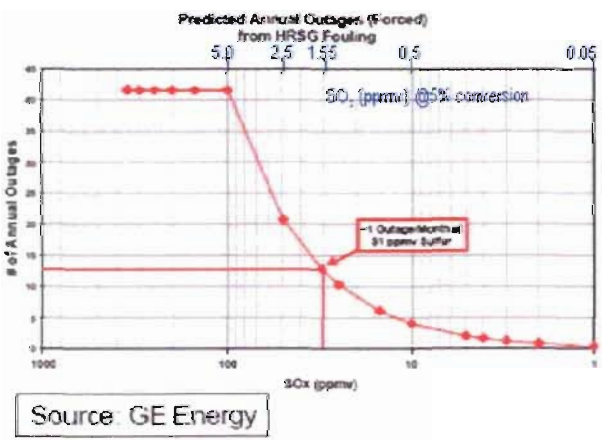
Response

Any amount of sulfur in the CT exhaust gas creates the potential for ammonium salt formation and deposition and/or acid corrosion in the heat recovery steam generator (HRSG). Problems such as these that lead to lower reliability, forced outages, or increased maintenance outages are unacceptable for a planned base-loaded unit such as Stanton Unit B. Even at the low levels that have been proposed for Stanton Unit B, sulfur in the turbine exhaust gas still has the potential to affect reliability. The claimed SO_2 emissions rate referenced above has not been demonstrated, permitted, or commercially guaranteed. Recently permitted IGCC plants using these reference plant technologies have not been permitted with SCR, nor are any other proposed plants proposing SCR.

A study performed by GE and presented by EPRI predicted the effects of ammonium bisulfate (ABS) formation on plant forced outage rates. The chart below shows the predicted forced outages caused by ABS as a function of SO_x concentration in the turbine exhaust gas. It is important to note that the chart reflects only 5-percent oxidation of SO_2 to sulfur trioxide (SO_3), which is an expected reaction in the CT. Therefore, the assumed SO_x concentration only contains 5 percent SO_3, the precursor to ammonium salts and acid gas. (Wabash River Generating Plant has reported 9-percent oxidation of SO_2.)

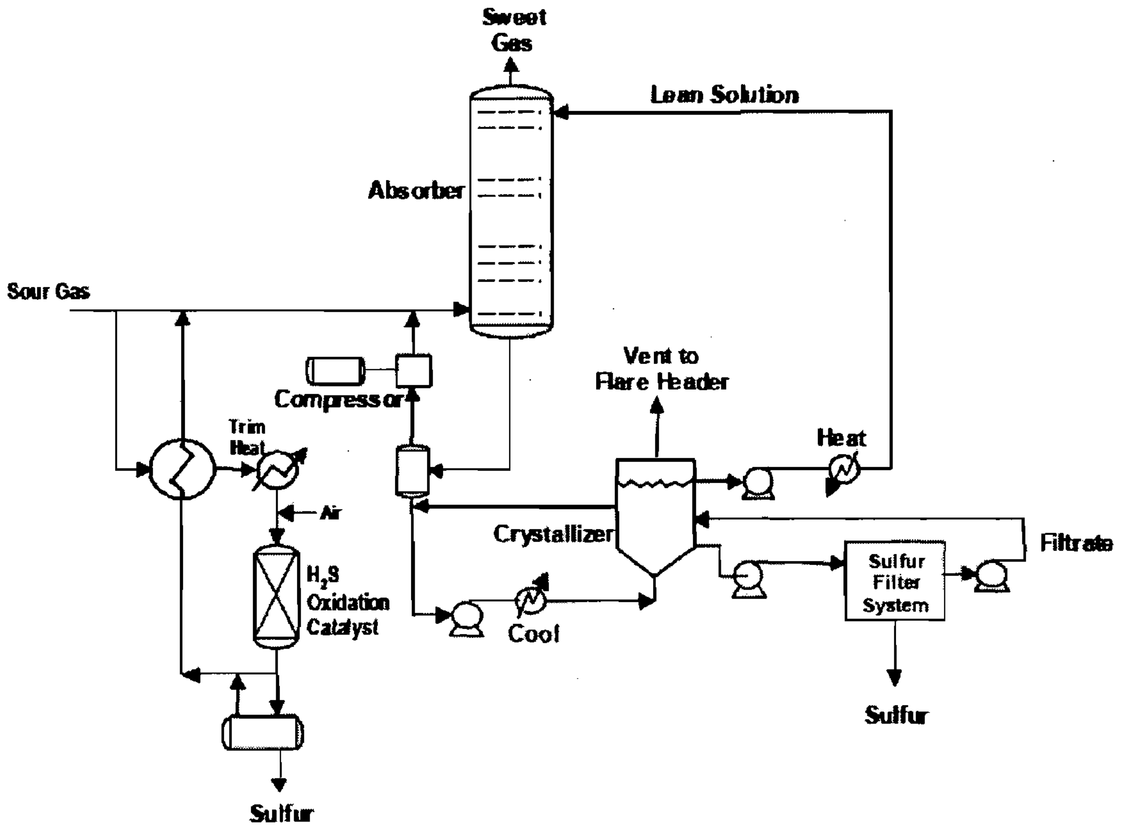
However, further oxidation of SO_2, which would be expected if an oxidation catalyst is used, would significantly exacerbate the problem of acid gas and ABS formation. The scale at the top of the chart shows the calculated SO_3 concentration based on 5-percent oxidation. If using an oxidation catalyst, 50- to 90-percent oxidation of SO_2 would be expected based on vendor information and EPRI reports. Based on the GE study, for a syngas sulfur concentration at the lowest theoretically achievable value, 50-percent oxidation could potentially cause seven unplanned shutdowns per year.

Until actual operational experience is gained, the precise amount of allowable syngas sulfur content is unknown. Based on the best information available, the use of an oxidation catalyst is not feasible.



Effect of Ammonium Bisulfate Formation on Plant Availability

__FDEP-13__—Please provide a description of the planned CrystaSulf technology planned for sulfur removal from the syngas prior to its combustion. Referring to the diagram below (from a CrystaTech paper), provide estimated liquid and gaseous (and constituent) flow rates to and from the absorption column necessary to ultimately achieve 0.015 lb SO_2/mmBtu. Include temperature and pressure of each stream.



__Response__

The CrystaSulf sulfur removal technology developed by CrystaTech converts hydrogen sulfide (H_2S) directly to elemental sulfur using a proprietary non-aqueous hydrocarbon-based scrubbing solution. This solution absorbs the H_2S in a conventional bubble-tray absorber, where the H_2S reacts with sulfur dioxide, itself physically absorbed in the scrubbing solution, to form elemental sulfur according to the classic liquid Claus process reaction. The CrystaSulf solution has a high solubility for product sulfur, which remains totally dissolved at the process operating temperature.

Rich solution from the absorber passes to a flash tank, and then the solution flows to a crystallizer, where the temperature is lowered and the solid sulfur crystals form. The crystallizer/filter area is the only area where sulfur solids exist within the process, and they are removed by a filter system. The crystallizer overflows to a surge tank, where a heater raises the solution temperature back to the circulating temperature and ensures that all elemental sulfur is dissolved in the solution. A conventional positive displacement pump transfers the solution back to the absorber (Reference CrystaSulf: H_2S Treating and Sulfur Recovery from Sour Gas, paper presented at the Asociación Venezolana de Procesadores de Gas (AVPG) 2002 Annual Meeting; Caracas, Venezuela)

With the CrystaSulf system, the maximum theoretical sulfur removal yields a syngas with approximately 4 parts per million by volume (ppmv) H_2S plus some similar amount of carbonyl sulfide (COS) (which is not removed by the CrystaSulf system). Further H_2S reduction is not possible due to the limitation of chemical equilibrium.

Further H_2S reduction is not possible due to the limitation of chemical equilibrium. More detailed information about the process, such as specific operating conditions, is proprietary information to CrystaTech, and SCS is prohibited from disclosing it under a confidentiality agreement between CrystaTech, Inc. and SCS.

FDEP-14—Calculate the same parameters to achieve 0.010 lb SO_2/mmBtu.

Response

As described in the response to FDEP-13, the CrystaSulf system has a maximum theoretical sulfur removal that yields a syngas with approximately 4 ppmv H_2S, and a similar COS concentration. Further H_2S reduction is not achievable due to the limitation of chemical equilibrium.

More detailed information about the process, such as specific operating conditions, is proprietary information to CrystaTech, and SCS is prohibited from disclosing it under a confidentiality agreement between CrystaTech, Inc. and SCS.

FDEP-15—_Calculate the cost per ton SO_2 removed to achieve 0.015, 0.010, and 0.005 lb/mmBtu (approximately 97, 98, and 99% removal)._

Response

For this unit, the applicant has proposed the maximum control for SO_2 that is considered "technically feasible" for purposes of BACT. The proposed Unit B SO_2 BACT emission limit of 0.015 lb/MMBtu is well below the SO_2 limits established as BACT for all currently permitted IGCC facilities (i.e., more than 10 times lower). The SO_2 BACT limit proposed for Unit B is also well below all recently proposed and permitted coal-fired projects. The Unit B proposed SO_2 emission limit is therefore considered to represent the "top alternative" in the top down SO_2 BACT analysis. Accordingly, cost-effectiveness data were not provided for the Unit B SO_2 BACT analysis

A removal efficiency approaching 99 percent could theoretically be achieved applying CrystaSulf. However, CrystaSulf has never been demonstrated in this type of process, and the applicant has not proposed a permit limit that assumes its maximum theoretical potential.

FDEP-16—_How does the sulfur concentration of the treated syngas compare with the specification for natural gas already used at Stanton Unit A?_

Response

The average sulfur content of natural gas, based on the U.S. Environmental Protection Agency (EPA) Acid Rain Program default value of 0.0006 lb/MMBtu of SO_2, used in Stanton Unit A is approximately 0.2 grain of sulfur per 100 standard cubic feet (gr S/100 scf). A syngas sulfur content of approximately 1 gr S/100 scf corresponds to the 0.015 lb/MMBtu of SO_2 BACT limit requested.

AMMONIA RELATED ISSUES

***FDEP-17*—Submit information indicating whether more (and how much more) ammonia (capable of forming fuel NO_x in the CT) is formed in the gasification step by using the KBR Transport Gasifier in an air-blown rather than oxygen-blown configuration. How will NH_3 in the syngas using the KBR Transport Gasifier compare with the constructed IGCC plants, such as TECO Polk Power Station that do not recover NH_3?**

Response

Based on actual operating data from the Power Systems Development Facility (PSDF), the amount of ammonia produced in either air-blown or oxygen-blown operation is approximately the same. The ammonia concentration is higher for the oxygen-blown case than for the air-blown case. Recovering ammonia for use as a byproduct does not increase the concentration in the syngas to the CT. Whether the ammonia is recovered for use as a byproduct or recycled to the gasifier, the same type of scrubber would be used to remove ammonia from the syngas. The amount of ammonia in the syngas is more directly related to the sub-bituminous fuel and the operating temperature of the gasifier, both of which are integral design elements of the project.

***FDEP-18*—Is the additional NH_3 formed in the gasification step ameliorated by the ammonia recovery process incorporated within syngas cleanup? Provide information comparing expected ammonia (NH_3) entering the CT for the KBR Transport Gasifier under air-blown versus oxygen-blown modes.**

Response

Whether the ammonia is recovered for use as a byproduct or recycled to the gasifier, the same type of scrubber would be used to remove ammonia from the syngas. The amount of ammonia entering the CT for both air-blown and oxygen-blown is approximately the same. Design studies have shown the NO_x emissions to be almost the same for either air- or oxygen-blown cases, with NO_x slightly less for the air-blown case. The amount of ammonia in the syngas is more directly related to the sub-bituminous fuel and the operating temperature of the gasifier, both of which are integral design elements of the project.

FDEP-19—The natural gas-fired Mystic Station meets 2.0 ppmvd NO_x @15% O_2 (1-hr basis), with 2.0 ppm NH_3 limit. It would seem that the low ammonia levels would solve the ammoniated sulfates/sulfites concerns when burning syngas. The values prior to the catalyst are in 30-40 ppm NO_x bracket firing natural gas according to staff at the Mystic Plant. That incoming value was what was offered at the time that Mystic was permitted. This is similar to the GE F-Class CT emission guarantee proposed for this project. Please advise the level of NH_3 slip that would concern the applicant with respect to claimed ammonium sulfate/sulfites fouling.

Response

Even though the CT will emit very low levels of SO_2, only a small amount of ammonia is needed to create ammonium salts. Accordingly, even low amounts of ammonia in the CT exhaust gas create the potential for ammonium salt formation, deposition, and corrosion in the HRSG. Problems such as these that lead to lower reliability, forced outages, or increased maintenance outages are unacceptable for a planned base-loaded unit such as Stanton Unit B.

FDEP-20—Because ammonia in the syngas is removed in the ammonia plant (prior to the CT), it seems that NO_x formation from ammonia during syngas combustion will be less than otherwise expected. Note that some of the oxygen-blown designs recirculate ammonia-containing sour water back to the coal preparation and slurrying steps rather than recovering ammonia. It would appear that the syngas from the proposed project should have no greater tendency to form fuel NO_x than syngas from the oxygen-blown processes (for which significantly lower pre-SCR NO_x guarantees are available). Please comment as to NO_x formation from ammonia from the proposed project when compared to other designs.

Response

As previously stated in the responses to FDEP-17 and FDEP-18, based on actual operating data from the PSDF, the amount of ammonia produced in either air-blown or oxygen-blown operation of the Transport Gasifier is approximately the same. The concentration is higher for the oxygen-blown case than for the air-blown case. Recovering ammonia for use as a byproduct does not increase or decrease the ultimate concentration in the syngas to the CT. Whether the ammonia is recovered for use as a byproduct or recycled to the gasifier, the same type of scrubber would be used to remove ammonia from the syngas.

***FDEP-21*—Problems related to ammonium/sulfate fouling can be ameliorated by: limiting the ammonia slip or SO_2; insuring sufficient SCR catalyst; choosing the correct formulation for the given stream; spacing of components within the HRSG, etc. Please describe considerations given to the design of these other components of the system as they relate to the minimization of ammonium/sulfate fouling in the HRSG.**

Response

To minimize ammonium salts and/or acid corrosion potential, the applicant has proposed the maximum SO_2 control that is considered technically feasible for this unit. Ammonia slip will be minimized to the extent practicable, which necessitates operating the proposed SCR at reduced efficiency. Consideration will also be given to HRSG designs that limit the negative effects of ammonium salt formation and/or acid corrosion. This would include issues such as component spacing, SCR catalyst formulation, and the exclusion of carbon monoxide (CO) catalysts. As noted in the Stanton Unit B PSD Application, CO catalysts greatly exacerbate the oxidation of SO_2 to SO_3, resulting in higher levels of ammonium salt and acid gas formation. The previously discussed EPRI information and the attached GE document both suggest that CO catalysts increase the oxidation of SO_2 to SO_3.

OTHER MISCELLANEOUS ISSUES

***FDEP-22*—The application contains no cost data in terms of $/ton for any of the pollution control strategies such that we can see why a particular endpoint was selected for control. In order to use the standard Top/Down determination method, we need to see cost considerations.**

Response

The levels of control proposed for Stanton Unit B for each pollutant represent the maximum level of control that is considered "technically feasible" for purposes of BACT. Therefore, in accordance with the *top down* determination method, economic analysis of the control effectiveness was not performed.

<u>FDEP-23</u>—Section 2.0 of the PSD Application, includes the subsection 2.2.1.5 Low Temperature Gas Cooling and Mercury (Hg) Removal. However, there is no description of the Hg removal process. Please provide a description of the Hg removal process (to the extent that the process is known or will be experimental). Provide an estimate of Hg removal in terms of percent reduction from levels in the incoming coal. Also estimate percent reduction based on values in the syngas to and from the Hg removal unit. The two estimates may be different if any Hg is removed via the fly ash or wastewater streams. Section 62-4.070, F.A.C.

<u>Response</u>

The mercury removal process will consist of an adsorption column containing activated carbon. The carbon is impregnated with sulfur at a concentration of approximately 10 to 15 weight percent. As the syngas flows through the sulfur-impregnated carbon bed, the mercury is adsorbed and reacts with sulfur form mercuric sulfide (HgS).

This technology has been demonstrated with coal gasification at the Eastman Chemical Company's chemicals from coal plant in Kingsport, Tennessee, which began operations in 1983. A 90- to 95-percent mercury removal has been reported with a bed life of 18 to 24 months.

While most of the hazardous air pollutant (HAP) metals emission rates estimated for the Stanton Unit B PSD permit application were calculated from emission factors for coal-fired IGCC plants (A Study of Toxic Emissions from a Coal-Fired Gasification Plant, EPRI Report #DCN 95-643-004-07, 1995), the mercury emissions were estimated based on a maximum mercury concentration from testing samples of PRB coal and an expected removal rate (90 percent) from the mercury removal system.

<u>FDEP-24</u>—Were other potential suppliers (for components other than the KBR Transport Gasifier) considered before selecting final equipment? These could include Siemens-Westinghouse and MHI who make F-Class CTs.

<u>Response</u>

Concerning other CT technology suppliers for syngas operation, SPC-OG also reviewed proposals submitted from Siemens and Mitsubishi. All were evaluated for initial cost, performance and life cycle costs. GE was evaluated to have the best and most complete proposal of the group. GE was the only supplier offering a full set of guarantees.

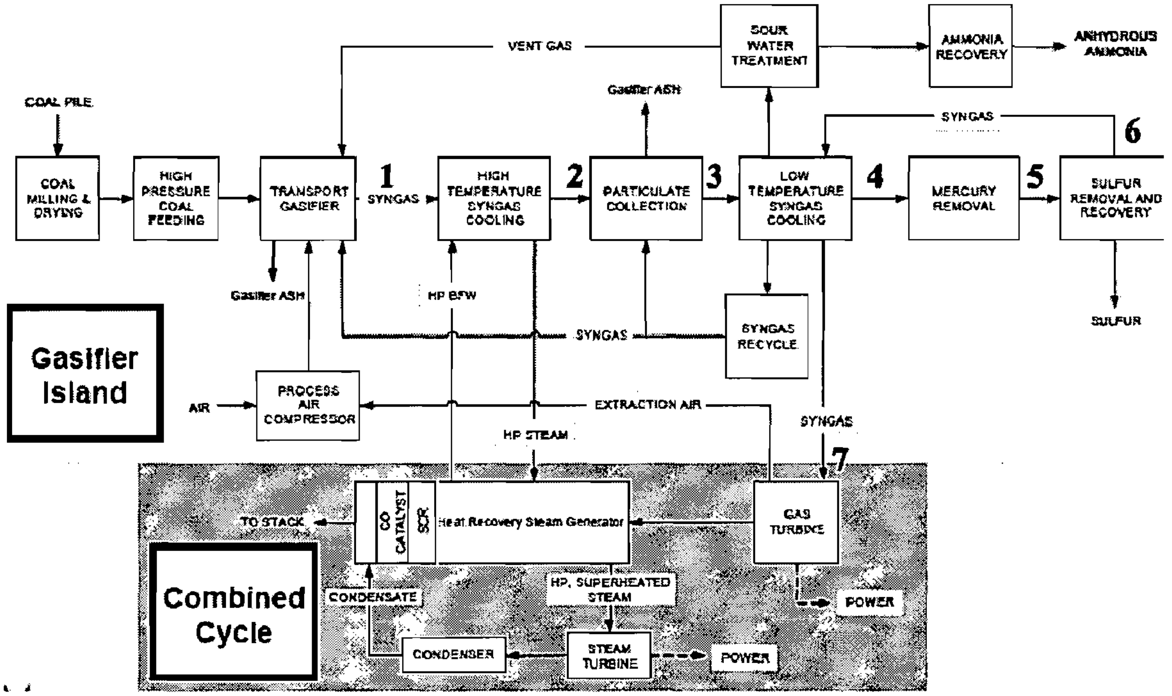
The response to question EPA-3 describes the review of sulfur removal technologies.

<u>FDEP-25</u>—Tables with emissions in terms of lb/hr (and ppmvd for NO_x, CO and VOC) have been provided for various operating scenarios. Provide table/s with emissions on the basis of ppm, lb/mmBtu, and lb/MWH for all pollutants for the project. Also include output in MW (gross and net) for each scenario.

<u>Response</u>

A table showing emissions in units of ppmv at 15-percent oxygen, lb/MMBtu, pounds per megawatt-hour gross (lb/MWh gross), and pounds per megawatt-hour net (lb/MWh net) for several representative syngas and natural gas operating scenarios is provided as an attachment. This table also includes the power output (gross and net) data that are presently available at the current stage of project design.

***FDEP-26**—Referring to the diagram on the following page (from a DOE presentation about the proposed project) and using the table on the same page, please provide best estimates of the concentrations (averages or ranges) of the key constituents and other indicated parameters for the syngas.*



Stream No.	*1*	*2*	*3*	*4*	*5*	*6*	*7*
Mole Fraction							
Ar							
CH4							
CO							
CO2							
H2							
H2O							
N_2							
O_2							
COS (ppm)							
H_2S (ppm)							
SO_2 (ppm)							
NH_3 (ppm)							
Temp. (°F)							
Pressure (psia)							

Response

	1	2	3	4	5	6	7
Mole Fraction							
Ar	0.0061	0.0061	0.0061	0.0061	0.0061	0.0065	0.0065
CH_4	0.0210	0.0210	0.0210	0.0210	0.0210	0.0222	0.0222
CO	0.2266	0.2266	0.2266	0.2271	0.2271	0.2393	0.2393
CO_2	0.0677	0.0677	0.0678	0.0680	0.0680	0.0700	0.0700
H_2	0.1143	0.1143	0.1143	0.1146	0.1146	0.1207	0.1207
H_2O	0.05222	0.0522	0.0519	0.0520	0.0520	0.0035	0.0035
N_2	0.5093	0.5094	0.5094	0.5105	0.5105	0.5377	0.5377
O_2	0	0	0	0	0	0	0
COS (ppm)	29	29	29	3.6	3.8	4.0	4.0
H_2S (ppm)	600	600	600	600	600	12	12
SO_2 (ppm)	0	0	0	0	0	0	0
NH_3 (ppm)	1700	1700	1700	60	63	67	67
HCN (ppm)	500	500	500	71	75	79	79
Temperature (°F)	1730	658	657	305	120	115	545
Pressure (psia)	530	511	501	486	481	461	452

***FDEP-27**—Also referring to the figure above, please explain how CO oxidation catalyst located in the lower temperature zone within the HRSG would function (e.g. with respect to SO_2 oxidation) in comparison with CO catalyst located prior to the HRSG where the applicant theorizes excessive SO_2 oxidation leading to operational problems.*

Response

The diagram was not intended to communicate CO catalyst operating in the lower temperature zone of the HRSG. Any CO catalyst would need to be installed in the high temperature zone near the leading edge of the HRSG to take advantage of the high temperature needed for catalytic conversion of CO. The applicant is not aware of a commercially available low temperature CO catalyst.

***FDEP-28**—Gasifier startup emissions from the startup stack and the flare for PM_{10} and VOC were estimated using AP-42 emission factors. It appears that CO, SO_2 and NO_x emissions were estimated using factors derived by Southern Company Services. Please provide the list of these factors and information as to how these factors were derived.*

Response

Factors for CO, SO_2, and NO_x emissions from the startup stack and flare were estimated based on vendor data and on parametric testing completed at PSDF. For emissions from natural gas combustion, AP-42 factors were used. For coal combustion, data compiled at PSDF show that carbon conversion would be approximately 99.9 percent, so approximately 0.1 percent of the carbon would be converted to CO; sulfur capture by calcium in the coal ash is approximately 90 percent, so approximately 10 percent of the sulfur would be converted to SO_2; and NO_x is approximately 0.15 lb/MMBtu.

FDEP-29—***The application indicates the use of good combustion practices to control emissions from the flare and the gasifier startup stack during startup events. Please describe measures that will be taken to minimize emissions during startups. How will startup durations be minimized? Please provide the basis for the 20 startup events per year estimate.***

Response

To the extent possible, startup duration and gas flows will be minimized, thus limiting emissions during startup. During gasifier startup on coal, the gas flow exiting the gasifier will be directed through the syngas cleanup process before being exhausted through the startup stack or combusted by the flare. Additionally, when possible, the gasifier will be kept as warm as possible, reducing the time required to return the unit to service.

The 20 startup events per year is conservatively estimated based on projected dispatch of the unit, availability expectations, and planned maintenance outages.

FDEP-30—***Syngas will be directed to the flare during "upset" conditions. How will this affect annual emissions? Can the number of expected upset periods/malfunctions be estimated based on past experience?***

Response

Stanton Unit B is a first of a kind IGCC facility, thus the number of expected upsets/malfunctions cannot be estimated based on past experience. During any upsets, syngas may be combusted by the flare potentially resulting in differences in emissions than if the syngas were being combusted in the CT. Upsets/malfunctions are not expected to have a significant effect on annual emissions.

***FDEP-31**—Startup of the combustion turbine/HRSG system will need to be addressed. Please describe expected numbers and durations of warm and colds start-ups of the CT/HRSG system as well as the steam turbine. Are the CT/HRSG and steam turbine started while firing natural gas then switched to syngas? Please describe the sequence of events during cold and warm startups and the points at which the system will be switched to syngas firing.*

Response

The combined-cycle island power block is designed to operate with either natural gas or syngas as fuel and is capable of continuous operations with either fuel. The Transport Gasifier is capable of beginning a start cycle without the combined-cycle power block necessarily being in service; however, the combined-cycle equipment will have to be at some level of operation using natural gas before transitioning to syngas as fuel. Heating the gasifier is described in Section 2.2.1.2 of the PSD application, as well as the transition of the CT from natural gas to syngas. Prior to this transition, the combined-cycle unit will be operating on natural gas. If the power block as well as the gasifier were out of service, the gas turbine will be started a minimum of 2 (warm start) or 4 (cold start) hours prior to the time the gasifier would be ready to supply syngas to the power block. The lead time is governed in part by the need to generate enough steam to synchronize the steam turbine generator before transitioning the combined-cycle to syngas. The transition between fuels is limited by the gas turbine manufacturer between 35 and 75 percent CT output.

As noted in Section 2.2.1.2 of the PSD application, the gasifier may take up to 24 hours (from a cold initial state) to reach operational conditions sufficient to allow the use of syngas in the combined-cycle. It is expected that the combined-cycle power block will be removed from service on average four times a year due to planned and unplanned maintenance requirements for periods longer than 36 hours, necessitating *cold* restarts. *Warm* starts will mark the end of short maintenance outages less than 36 hours in duration, which are expected to occur less than 16 times a year on average. In any case, the minimum period for such a maintenance outage would be at least 8 hours. It should be noted that the CT will not be equipped with a HRSG bypass stack; so, to prevent damaging the HRSG internals, the steam turbine will have begin operating soon after the gas turbine reaches its natural gas minimum load point of 50 percent.

***FDEP-32**—According to Section 5.2.3 of the PSD application report, the "crushing and storage (i.e., silos and bins) operations will be equipped with baghouses". The application seems to include coal storage silo and coal mill silo baghouses only (listed in Table A-20). Should there be one or more baghouses associated with a coal mill or coal grinding process? Generally these grinding operations have much higher baghouse flow rates than those listed in Table A-20.*

Response

Coal is introduced into the mill where it is pulverized and dried. The coal is conveyed out of the mill to a baghouse (this is the baghouse that handles the large flow referred to in the question). The solids are separated from the gas stream and sent to the PC silo. From the baghouse, the clean gas is sent to a condenser where it is cooled, and moisture is removed from the system. The condensate is filtered and sent to a water treatment facility. From the condenser, the cooled gas is sent to a heat exchanger where it is heated. The heated gas is returned to the mill to dry the coal.

MODELING ISSUES

***FDEP-33**—According to the application, the project will contribute over 100 tons per year of VOC and over 100 tons per year of NO_x, precursors to ozone formation. Therefore, the ambient air quality analysis must include an analysis of ozone. The application includes ozone data to support the preconstruction monitoring requirement but the Department needs further information to complete the ambient air quality analysis with respect to ozone. Please provide an analysis to support a conclusion that there will not be a violation of the ambient air quality standard for ozone due to this project.*

Response

Ozone is formed in a complex series of chemical reactions involving primarily NO_x and volatile organic compounds (VOCs) during warm ambient temperatures in the presence of sunlight. Since ozone is formed from precursor pollutants, assessment of ambient ozone impacts is typically conducted on a regional basis using resource-intensive models such as the EPA Community Multiscale Air Quality (CMAQ) model.

Estimated potential NO_x emissions from Unit B are 1,006.2 and 611.4 tons per year (tpy) during Phase I and Phase II, respectively. Estimated potential VOC emissions from Unit B are 128.9 tpy. These annual emission rates are relatively minor in comparison to regional emissions. For example, total Orange County NO_x and VOC emissions in 1999 were 41,952 and 43,828 tons, respectively. Accordingly, Unit B potential NO_x (during Phase I) and VOC emissions will be only 2.4 and 0.3 percent of total Orange County NO_x and VOC emissions, respectively.

Ambient ozone levels in Orange County are primarily due to ozone transport from up-wind areas and regional NO_x and VOC emissions resulting from motor vehicle activity. In 1999, motor vehicle NO_x and VOC emissions comprised 76.5 and 71.3 percent, respectively, of total Orange County NO_x and VOC emissions. Despite significant increases in population and motor vehicle activity, ambient ozone air quality in Orange County has improved over the last 5 years due to improvements in motor vehicle emission rates. For example, the 4th highest 8-hour average ozone concentration at the Winegard Road monitoring station in Orlando was 0.083 part per billion (ppb) in 2000 and 0.078 ppb in 2005. Continued reductions in average motor fleet emissions would be expected to further improvement Orange County ozone air quality. In addition, the Clean Air Interstate Rule (CAIR) will result in significant actual reductions in existing power plant NO_x emissions throughout Florida.

In summary, the relatively minor NO_x and VOC emissions associated with Unit B will not significantly impact ambient ozone levels in Orange County. Orange County is projected to remain in compliance with the ozone ambient quality standard due to the continued significant reductions in regional motor vehicle and power plant emissions.

***FDEP-34*—AERMET surface parameters are identified for each sector that make up a 3 km radius. In the modeling analysis, 5 sectors are used to make up the 3km radius. It is recommended that 12 sectors be used for all analyses. Making the number of sectors smaller decreases the importance of the surface parameters in each application.**

Response

Five sectors were chosen to represent the land use within 3 kilometers (km) of the Stanton Energy Center due to the homogenous nature of each sector. An aerial showing land use in the vicinity of the Stanton Energy Center was provided in Figure 2-3 of the PSD permit application. As shown in this figure, the 3-km area surrounding the site can be represented in five sectors without losing any accuracy in the land use determination. Figure 6-4 of the PSD permit application shows a similar categorization of land use. Accordingly, the use of five sectors is considered to adequately represent land use within 3 km of the Stanton Energy Center given the relative uniformity of land use. Increasing the number of sectors to 12 would, for the most part, simply duplicate the land use sectors already shown.

***FDEP-35*—One of the surface parameters in AERMET is albedo. Please explain why the hours of sunrise and sunset have an albedo value higher than any value listed in guidance.**

Response

The albedo value provided in the AERMET input files is for midday. The midday value is the minimum value that albedo will achieve during the course of a day. These minimum albedo values are provided in Table 4-1 (page 4-49) of the User's Guide for AERMOD Meteorological Preprocessor (AERMET). As the angle from the sun to the ground (solar elevation angle) decreases in the afternoon the calculated albedo increases, as demonstrated in equation 5.7 (page 5-12) of the AERMET user's guide. In the morning, the calculated daily albedo will be highest at sunrise and will gradually decrease upon the increasing solar elevation angle.

***FDEP-36**—The text of the application was revised with regards to the Class I analysis, including Deposition. Please provide any associated modeling if needed.*

Response

All project modeling files, including the Class I area assessments, were provided to FDEP on a compact disc (CD) in March 2006.

***FDEP-37**—The AERMET files show that station 12842 was used for the Upper Air Data and station 72205 was used for the Surface Data. The text in the application states that 92801 (upper air) and 12815 (surface) was used. Please explain.*

Response

The stations identified in the AERMET files are correct. The surface station located at the Orlando International Airport (OIA) has two identification numbers: (a) World Meteorological Organization (WMO) Station No. 72205 and, (b) Weather-Bureau-Army-Navy (WBAN) Station No. 12815. Therefore, both of these station numbers can be used to identify the surface station located at OIA. The meteorological data provided by the National Climatic Data Center (NCDC) used the WMO station number. Since WBAN station numbers are more widely used than the WMO station numbers, the OIA WBAN station number was included in the text of the PSD permit application.

Upper air data used for the Unit B modeling assessment was collected at the upper air station currently located in Ruskin, Florida. The upper air station for the Tampa Bay area was located at the Tampa International Airport (TPA) from 1993 through September of 1996; the TPA station is identified by WBAN Station No. 12842. The Tampa Bay area upper air station was moved to Ruskin, Florida, in January 1996. The PSD permit application was revised to indicate WBAN Station No. 92801 for the Ruskin upper air station since that station number is shown in the NCDC database as being located in Ruskin, Florida. Although the Ruskin upper air station is physically situated at a different location than the TPA meteorological station, NCDC has advised Environmental Consulting & Technology, Inc. (ECT), that that the upper air station located at Ruskin has been assigned the same WBAN number – No. 12842. As noted previously, upper air data used for the Unit B modeling assessment was collected at the upper air station currently located in Ruskin, Florida.

OTHER COMMENTS

FDEP-38*—Attached are preliminary comments from EPA Region 4. We have not yet received any comments from the U.S. Fish and Wildlife Service. We will pass these on if and when received. Either agency might submit comments during the sufficiency review or during the normal comment period following initial Department action.

Response

No response required.

B. U.S. ENVIRONMENTAL PROTECTION AGENCY
Letter from Jim Little (EPA) to Cindy Mulkey (FDEP), Dated April 4, 2006

EPA-1*—Phase I Nitrogen Oxides Emissions Rate—The proposed combustion turbine nitrogen oxides (NO_x) emissions rate for the initial demonstration phase (first four years of operation) is 20 ppm based on applying selective catalytic reduction (SCR) control technology to an uncontrolled NO_x emissions rate of 40 ppm. The application does not provide much information on why the uncontrolled rate is as high as 40 ppm and why use of SCR would not result in better than 50 percent control efficiency. We recommend that FDEP request additional information from the applicant on this subject.

Response

The applicant has supplied additional information regarding the NO_x emission rate to FDEP in response to its request.

EPA-2*—Phase II Nitrogen Oxides Emissions Rate—OUC proposes a Phase II combustion turbine NO_x emissions rate of 12 ppm "unless the Phase I technical report demonstrates that Unit B cannot technically achieve this level of NO_x control." Stating the proposed Phase II emissions rate on a contingent basis will complicate FDEP's development of permit terms and conditions. If you reach the point of developing permit terms and conditions for this project, we will be glad to assist as needed in drawing up practically enforceable language for NO_x emissions.

Response

The applicant assumes that this coordination will occur during the normal review process of the Stanton Unit B PSD Permit.

EPA-3*—Sulfur Removal Process—Section 2.2.1.6 in the permit information contains a description of the sulfur removal process, but not much information is provided. The sulfur content of the synfuel burned in the combustion turbine directly affects sulfur dioxide emissions.

Sulfur content can also affect the frequency at which the heat recovery steam generator (and therefore the combustion turbine) might have to be shut down for cleanout of deposits resulting from conversion of sulfur compounds by the catalyst in the SCR system. We would like to know more about the type of sulfur removal system planned for this project and information about the feasibility of optional sulfur removal systems that might reduce synfuel sulfur content.

Response

The sulfur removal process used as the design basis is the CrystaSulf technology developed by CrystaTech. This process converts H_2S directly to elemental sulfur using a proprietary non-aqueous hydrocarbon-based scrubbing solution. This solution absorbs the H_2S in a conventional bubble-tray absorber, where the H_2S reacts with sulfur dioxide, itself physically absorbed in the scrubbing solution, to form elemental sulfur according to the classic liquid Claus process reaction. The CrystaSulf solution has a high solubility for product sulfur, which remains totally dissolved at the process operating temperature.

Rich solution from the absorber passes to a flash tank, and then the solution flows to a crystallizer, where the temperature is lowered and the solid sulfur crystals form. The crystallizer/filter area is the only area where sulfur solids exist within the process, and they are removed by a filter system. The crystallizer overflows to a surge tank, where a heater raises the solution temperature back to the circulating temperature and ensures that all elemental sulfur is dissolved in the solution. A conventional positive displacement pump transfers the solution back to the absorber (CrystaSulf: H_2S Treating and Sulfur Recovery from Sour Gas, paper presented at the AVPG 2002 Annual Meeting; Caracas, Venezuela)

Detailed information about the process such as specific operating conditions is proprietary information protected by a confidentiality agreement between CrystaTech, Inc., and SCS.

Commonly used technologies such as rectisol, selexol, and amine units were deemed not effective for this application due to the low inlet sulfur concentrations. Amine, rectisol, and selexol processes are typically used to clean gas streams with high sulfur concentrations. An amine, rectisol, and selexol process would remove the hydrogen sulfide from the syngas, but would require a separate Claus unit to convert the hydrogen sulfide to elemental sulfur. The CrystaSulf unit captures the hydrogen sulfide and converts it to elemental sulfur in one system. Further, the amine, rectisol, and selexol processes have higher steam requirements than the CrystaSulf unit. This process steam would be extracted from the steam cycle and would significantly reduce plant efficiency. These types of systems would not be expected to have higher sulfur removal efficiencies than that predicted by CrystaSulf.

What primarily drove the technology decision was the low sulfur loading in the syngas. Due to the low loading, there were other technologies that were more economical from a capital cost and an operating cost. Four other technologies were evaluated besides CrystaSulf: a conventional Lo-Cat, Lo-Cat Auto Circulation, Paques, and Xergy. Results from this evaluation showed that conventional Lo-Cat units have had problems with sulfur pluggage and foaming at high pressures. Lo-Cat Auto Circulation and Paques required an amine unit upstream to concentrate the H_2S stream and operate at low pressure. This increased both the capital cost and utility demand to prohibitive levels. Xergy is a developmental technology, and the company declined to provide information for the project. None of these technologies were expected to have higher sulfur removal efficiencies than that predicted by CrystaSulf.

<u>EPA-4</u>—Mercury—Although mercury is not considered a regulated new source review (NSR) pollutant under recent NSR rule revisions, mercury emissions are always of interest. The description of mercury controls for this project is very brief. (We could only find one sentence on this topic.) We recommend that FDEP request additional information on mercury controls. We would also like to know if the mercury emissions estimate in Table A-7 takes mercury controls into account. Footnote 1 in this table indicates that combustion turbine emissions rates for hazardous air pollutants including mercury are from a document entitled A Study of Toxic Emissions from a Coal-Fired Gasification Plant (no date or author). The mercury emissions derived from this study may not apply to a gasification facility with mercury controls.

<u>Response</u>

The applicant has supplied additional information regarding the planned mercury removal technology to FDEP in response to its request in question FDEP-23.

While most of the HAPs metals emission rates estimated for the Stanton Unit B PSD permit application were calculated from emissions factors for coal-fired IGCC plants (A Study of Toxic Emissions from a Coal-Fired Gasification Plant, EPRI Report #DCN

95-643-004-07, 1995), the mercury emissions were estimated based on a maximum mercury concentration from testing samples of PRB coal and an expected removal rate (90 percent) from the mercury removal system. A revised Table A-7 with a footnote indicating the source of the mercury emissions estimate is attached.

***EPA-5*—Effect of IGCC Facility on Existing Stanton Energy Center Emissions Units—The proposed IGCC facility will be located at the existing OUC Stanton Energy Center. We would like to know if operation of the IGCC facility will affect operations and emissions from existing Stanton Energy Center emissions units.**

Response

Stanton Unit B is not expected to have any significant effects on the existing Stanton Energy Center emission units. Stanton Unit B will utilize existing infrastructure and systems where appropriate, but will operate as an independent power generation unit.

***EPA-6*—Flare Emissions—OUC states that the flare for the gasification trains will activate "during startup and shutdown of the IGCC unit and during facility upsets." What is meant by "IGCC unit" - certain components within the gasifier area or all components within the facility including the combustion turbine? An estimate of flare annual emissions is provided in Appendix A, but we are unable to tell the basis for this estimate. For example, how many flaring events were assumed for the emissions estimate?**

Response

The IGCC unit is the combination of all components of the gasification island and the combined-cycle unit. The multipoint flare is designed to combust any syngas that the gas turbine is unable to burn, either due to the gas turbine being off-line or due to syngas quality (or quantity) being outside the specifications set forth by the gas turbine manufacturer. The technical limits for operating the IGCC unit are designed to balance syngas production and gas turbine demand, preventing load rejections that would require operation of the flare to consume the unusable syngas.

The calculations in Appendix A assume 20 flare events per year, which is estimated based on projected dispatch of the unit, availability expectations, and planned maintenance outages.

C. ORANGE COUNTY ATTORNEY'S OFFICE
Letter from Anthony Cotter (Assistant County Attorney) to Hamilton Oven (FDEP), Dated March 29, 2006

ORANGE-1—Orange County is currently an air quality: attainment maintenance area for ozone (Rule 62-204.340(4)(a)1). We are concerned that Orange County may soon exceed the 8-hour ozone National Ambient Air Quality Standard (NAAQS). A number of our 2004 and 2005 8-hour average ambient ozone concentrations have exceeded the NAAQS standard for ozone. In fact, if our fourth highest 8-hour average ozone concentration in 2006 exceeds 94 ppb, Orange County will have exceeded the 0.08 ppm ozone NAAQS standard in a rolling three-year average, and may be reclassified as a nonattainment area. Ambient ozone concentrations vary with the weather, and are hard to predict. However, we saw no discussion of Orange County's high current ozone concentrations in the application. We also note that applicant chose ambient pollutant data that does not accurately reflect current and past ozone exceedances. The data presented in SSCA Volume II Table 8-1 is for years 2000 through 2004. This data set omits years 1997 through 1999 and 2005, during which a number of exceedances of the current 8-hour ozone standard were measured in the county. We view the application as insufficient in that regard, and request that applicant present and discuss all publicly available air quality data for the county for the past 10 years.

Response

The supplemental site certification application (SCA) presented the most recent 5-year set of ambient air monitoring data that was available at the time of application preparation. This period of record is typical or standard for SCAs and is considered representative. These data are presented in Volume 1, Table 2.3-19, beginning at page 2-114, as well as in the referenced table in Volume 2. In response to this question, these tables have been updated to include the 2005 data for all pollutants. In addition, for ozone the additional data for the years 1995 through 1999 have also been inserted. A review of this ozone data for the county for the last 11 years indicates that the 4th highest 8-hour average ozone concentration has never exceeded 90 ppb (1998, Winegard Road).

It is noted that a discussion of ambient air quality is found in Volume 1 beginning at page 2-118. This discussion specifically notes that ozone is the air pollutant "primarily affecting air quality in Orange County."

<u>ORANGE-2</u>*—*The applications use data dated prior to year 2000, including housing price data that has changed significantly in the past few years. Applicant should update application to reflect the latest available information.

<u>Response</u>

According to the 2005 Florida Statistical Abstract, the purchase price of a house in Orange County was $177,886 in 2004 and $232,374 in 2005. The comparable prices for all houses in Florida are $188,700 in 2004 and $246,500 in 2005. The median home value in Orange County in 2002 was $125,062, in 2003 it was $144,072, and in 2004 the median home value was $149,999, according to the Metro Orlando Economic Development Commission Web site. According to the same Web site, the median renters cost in Orange County was $773 in 2002, $821 in 2003, and $875 in 2004. This response provides the requested information and should be considered an update to the supplemental SCA submittal.

<u>ORANGE-3</u>*—*SSCA Volume I Table 5.6-2 compares Unit B emissions to Orange County's emissions and shows its prospective impact on Orange County. The table does not include Stanton as a whole, that is, Units 1, 2, and A, as well as the proposed Unit B. Furthermore, the application lacks an appropriate discussion of how the cumulative impact of the 4 Stanton units on Orange County. We request that this analysis be included.

<u>Response</u>

The emissions data for Stanton Units 1, 2, and A were provided in Table 2.3-21, on page 2-129. An assessment of cumulative air quality impacts was not required since emissions from Unit B were predicted to result in insignificant impacts, as presented in Section 5.6.1.4, beginning on page 5-13.

ORANGE-4*—SSCA Volume II Page 1-6 states that an 80% reduction of NO_x to 5 ppm is proposed as BACT for Unit B. If the NO_x goal is 20 ppm, reduction to 5 ppm is a 75% reduction, not 80%, and this should be corrected.

Response

The proposed NO_x BACT limit for Unit B when fired with natural gas is 5 ppm. The Unit B GE 7FA CT will be equipped with a diffusion flame type combustor since this is the only type of GE combustor that is capable of combusting both syngas and natural gas. The GE NO_x guarantee for their natural gas-fired 7FA CT equipped with a diffusion flame combustor and water injection is 25 ppm. Accordingly, a decrease in NO_x concentration from 25 to 5 ppm equates to an 80-percent reduction. The 20-ppm goal is applicable to syngas operations during the demonstration period.

ORANGE-5*—SSCA Volume II Table 2-4 shows an emission rate for NO_x of 42.6 lb/hr at 70°F ambient temperature, using natural gas. At 8760 hr/yr, the result is 187 tons per year (TPY) NO_x. Page 1-6 states that 5 ppm NO_x with 5 ppm ammonia slip is expected for natural gas firing with SCR. This appears likely to be significantly greater than 187 TPY NO_x, if 20 ppm NO_x yields approximately 992 TPY NO_x. Please explain the assumptions used in SSCA Volume II Tables 2-2, 2-3, and 24.

Response

Because the volumetric exhaust flow rates for the combined cycle unit at 15-percent oxygen differ depending on whether syngas or natural gas is being combusted, it is not possible to ratio NO_x concentrations in units of ppm to estimate mass emission rates in units of tpy. The NO_x emission rates during natural gas-firing were calculated based on an SCR-controlled outlet concentration of 5.0 ppm at 15-percent oxygen and the volumetric exhaust flow rates that will occur during natural gas combustion. Estimated combined cycle exhaust flow rates for syngas and natural gas combustion are shown in Appendix A, Tables A-13 and A-14, respectively.

ORANGE-6*—Please provide details of the performance parameters to be investigated during the Phase I demonstration program, including the combustion turbine, duct burner, gasification system and SCR or any other emission control systems.

Response

Monitoring of the project's performance will be conducted for various reasons. The overall test program objectives will include the following:

- Optimizing the gasifier performance.
- Monitoring equipment thermal and mechanical performance.
- Investigating high-temperature, high-pressure (HTHP) filter operational performance.
- Optimizing the gas turbine syngas combustor performance.
- Monitoring the gas turbine internals.
- Monitoring and optimizing HRSG performance.
- Optimizing SCR performance.
- Optimizing and improving process control systems.
- Improving startup and load-following capability.
- Monitoring the gasification ash landfill site.
- Evaluating the use of the gasifier ash as a fuel source.
- Completing a full survey to characterize all the egress streams.
- Compiling plant repair and maintenance records.
- Completing thorough inspections of all plant equipment.
- Alternative sub-bituminous coal test.

The plant will be operated under commercial dispatch and the test data will be collected at commercially representative conditions.

In addition to overall system performance, monitoring of environmental performance parameters will also be carried out. A discussion of emissions monitoring to comply with Clean Air Act (CAA) requirements was provided in Volume 1, Section 5.6.2, page 5-20.

Monitoring of emissions and emission control systems will comply with these requirements, at a minimum.

***ORANGE-7*—On SSCA Volume II pages 20-22 of the PSD application, NO_x allowable emissions are given for Phase I, Phase II and gas-fired operation. All of these cases appear to be for the CT with DB operating only. Sections for other pollutants give allowable emissions for operation with and without DB operation. Is applicant not proposing NO_x allowable emissions for operations without the DB, or will the allowable emissions apply with or without the DB?**

Response

The requested allowable NO_x emission rates reflect the use of SCR control technology and apply with or without duct burner operation.

***ORANGE-8*—It appears that the SCR will operate with an ammonia slip of 5 ppm. How much ammonia will this amount to in TPY? What is the odor threshold for ammonia, and is an ammonia odor ever noticed from other units at Stanton that use an SCR?**

Response

Initially, the SCR control system with fresh catalyst will result in low levels of ammonia slip. Ammonia slip concentrations will gradually increase over time, up to a maximum of 5 ppm, as the SCR catalyst activity decreases. Based on natural gas combustion for 8,760 hours per year (hr/yr) at 100-percent load with duct burner firing (Operating Case No. 7), ammonia emissions will amount to 67.4 tpy assuming an ammonia slip concentration of 5 ppm.

As indicated in the American Industrial Hygiene Association (AIHA) publication Odor Thresholds for Chemicals with Established Occupational Health Standards, the average odor threshold for ammonia is 17 ppm. The applicant is not aware that odors due to ammonia slip have been noticed from the existing Stanton units that employ SCR control technology.

ORANGE-9—Why, on SSCA Volume II page 34 and 38 of the PSD application, does field 3 contain "Pipeline Natural Gas" but the comment implies that field 3 should contain an allowable emission?

Response

Consistent with FDEP practice, the specification of pipeline natural gas is used as a means of limiting SO_2 emissions from natural gas turbines.

ORANGE-10—SSCA Volume II Section 5.2.3 proposes a 5% opacity limit for the coal handling operation, but the PSD application requests a 20% opacity limit. Applicant needs to explain the discrepancy.

Response

The application form has been corrected to indicate a proposed limit of 5 percent (see attached).

ORANGE-11—SSCA Volume II Table 5-3 proposes a PM/PM_{10} BACT limit of 0.013 lb/MMBtu for syngas operation, yet Table 5-1 shows that the best available control technology achieved by the average syngas combined cycle plant is 0.010 lb/MMBtu, and the best is 0.007 lb/MMBtu. The proposed PM/PM_{10} BACT limit for Unit B on syngas appears to be too high. The proposed PM/PM_{10} BACT limit for natural gas operation is 0.017 lb/MMBtu. This appears comparable to pulverized coal boilers presented in Table 5-2, and also appears too high. For reference, Orlando Cogen facility ID 0950203 is a natural gas-fired CT/DB cogeneration plant with a PM/PM_{10} permit limit of 0.01 lb/MMBtu, below the proposed BACT for Unit B.

Response

Table 5-1 includes only two IGCC facilities that were permitted, built, and operated. Of these, the only operating IGCC that has a permit limit for particulate matter (PM) is the Polk Power Station, with a limit of 0.013 lb/MMBtu. The only other operating facility from Table 5-1 (Wabash River Generating Station) does not have a permit limit for PM. Neither of these facilities uses an air-blown, non-slagging Transport Gasifier. Therefore, it is not always appropriate to assume a direct comparison can be made. Nonetheless, the proposed PM BACT on syngas for Stanton Unit B is consistent with the Polk Power Station permit limit and is below what has been estimated by the turbine vendor.

Stanton Unit B will be equipped with a diffusion flame burner (the only type of burner capable of combusting syngas). The PM limits proposed for natural gas operation are based solely on vendor estimates.

ORANGE-12—***SSCA Volume II Table 5-6 proposes a CO BACT limit of 0.050 lb/MMBtu for syngas operation with DB, yet Table 5-4 shows the best available control technology achieved by the average syngas combined cycle plant is 0.023 lb/MMBtu, and the best is 0.007 lb/MMBtu. The proposed CO BACT limit for Unit B on syngas appears to be too high. The proposed Unit B CO BACT limit for natural gas operation is 0.060 lb/MMBtu, which also appears too high. Again, referencing Orlando Cogen, it has a CO emission of approximately 0.034 lb/MMBtu, below the proposed BACT for Unit B.***

Response

Table 5-4 includes only two IGCC facilities that were permitted, built, and operated. The operating IGCC's that have permit limits for CO are the Polk Power Station with a limit of 0.044 lb/MMBtu and the Wabash River Generating Station with a limit of 0.05 lb/MMBtu. Neither of these facilities uses an air-blown, non-slagging Transport Gasifier. Therefore, it is not always appropriate to assume a direct comparison can be made. Nonetheless, the proposed CO BACT on syngas is consistent with these permit limits.

Stanton Unit B will be equipped with a diffusion flame burner (the only type of burner capable of combusting syngas). The CO limits proposed for natural gas operation are based solely on vendor guarantees.

ORANGE-13—***SSCA Volume II Table 5-6 proposes a VOC BACT limit of 0.011 lb/MMBtu for syngas operation with DB, yet Table 5-4 shows that the best available control technology achieved by the average syngas combined cycle plant is 0.0048 lb/MMBtu, and the best is 0.0017 lb/MMBtu. The proposed VOC BACT limit for Unit B on syngas appears too high. The proposed Unit B VOC BACT limit for natural gas operation is 0.013 lb/MMBtu, which also appears too high. Orlando Cogen has a VOC emission of approximately 0.0066 lb/MMBtu, below the proposed BACT for Unit B.***

Response

Table 5-4 includes only two IGCC facilities that were permitted, built, and operated. Of these, the only operating IGCC that has a permit limit for VOCs is the Polk Power Station with a limit of 0.0017 lb/MMBtu. The only other operating facility from Table 5-4 (Wabash River Generating Station) does not have a permit limit for VOC. Neither of these facilities uses an air-blown, non-slagging Transport Gasifier. Therefore, it is not always appropriate to assume a direct comparison can be made.

Stanton Unit B will be equipped with a diffusion flame burner (the only type of burner capable of combusting syngas). The VOC limits proposed for natural gas operation are based solely on vendor guarantees.

ORANGE-14—***SSCA Volume II Section 6.1 states that Orange County is designated an attainment area for all criteria pollutants. However, Rule 62-204.340(4)(a)1, F.A.C., designates Orange County as an air quality maintenance area for the air pollutant zone.***

Response

Orange County is an attainment area and is also designated as a maintenance area. Please refer to the response to Question Orange-1 for additional information.

***ORANGE-15*—The SSCA lacks detailed analysis of the 100-year floodplain within the site and the proposed alteration of this floodplain by the project. Detailed analysis should be submitted by applicant to show no increase in discharge to the downstream of the project site or what amount of increase will occur. Similarly, analysis should be submitted on the impact on the 100-year elevation of the floodplain located upstream of the project site.**

Response

As was stated on page 2-8 in Volume 1, "[a]ll Unit B facilities will be located above the 100-year flood elevation." That is, no construction of any facilities associated with the project will occur within any area designated as within a flood zone. Pursuant to the initial site certification of the Stanton Energy Center in 1982, the land elevation of the main 1,110-acre power plant area was raised at the time of initial plant construction in the early 1980s. The only construction associated with the Unit B project that will occur outside the main power plant area will be the onsite transmission interconnection. This area is also at an elevation above the 100-year flood elevation. Thus, no impacts on the 100-year floodplain upstream, downstream, or at the site will result from the Unit B project. With the addition of Stanton Unit B, the Stanton Energy Center will continue to be a zero discharge site.

***ORANGE-16*—The project site is located within Econlockhatchee Basin. FDEP has listed portions of the river in the vicinity of the project site as "impaired," requiring the establishment of TMDL. Applicant should submit a detailed analysis of whether the project site will contribute additional pollutants to the surface water body.**

Response

As discussed in Volume 1, Section 5.1, all cooling tower blowdown and process effluents generated by Unit B's operations will be discharged to existing Stanton wastewater management and reuse systems. There will be no discharge of cooling or other process wastewater to any surface waters. Therefore, Stanton Unit B will contribute no additional pollutants to any surface water body.

ORANGE-17—It can reasonably be expected that large and overweight loads will need to be brought on to the site during construction. The County is concerned that these loads may damage the public roads and drainage structures and that if the damage occurs adequate repairs may not be done. Applicant should address this issue in more detail in the SSCA and explain whether it is likely that these matters will occur and, if so, what they intend or proposed to do about it.

Response

It is required that all contractors adhere to applicable Department of Transportation (DOT) regulations when transporting materials and equipment to the site. Consistent with the construction of the existing Stanton units, oversize components will be delivered to the site by rail.

ORANGE-18—The ability of the existing Stanton Energy Center cooling water pond to adequately accommodate increased cooling water flows was not addressed at all by applicant and we believe it should be. If the existing pond does not have sufficient capacity, then either the existing pond will need to be enlarged or another pond constructed to prevent the existing pond from overflowing or experiencing other negative consequences.

Response

The existing cooling water pond was designed and constructed with enough capacity to support four PC units (2,000 MW) in accordance with the original site certification. Therefore, the existing pond has sufficient capacity and will not need to be enlarged, and no new ponds will need to be constructed.

ORANGE-19*—The ability of existing Stanton cooling water pipelines from Orange County to adequately accommodate increased cooling water flows was not addressed at all by applicant and we believe it needs to be. If the existing pipelines do not have sufficient capacity, then additional pipelines may need to be constructed.

Response

The pipeline was also designed and constructed to supply cooling water for four PC units. Additionally, Orange County has recently upgraded its pumps and has committed to supply the requested increase in cooling water flows.

ORANGE-20*—On page 3-48 and page 5-30 of the SSCA mention is made of the need for a greater supply of treated effluent, but the SSCA fails to provide an estimate of the increase. More specificity should be provided by the applicant on this issue.

Response

As stated on page 3-48 and further detailed in Table 3.5-1 (Water and Wastewater Stream Flowrates) of the supplemental SCA, approximately 2.6 million gallons per day (MGD) additional treated effluent will be needed for Stanton Unit B.

ORANGE-21*—Section 6.0 of the SSCA discusses the proposed route for transmission lines, but neglects to discuss or include a proposed route for the reclaimed water supply pipeline which will be needed as well. Applicant should include this information.

Response

No additional pipeline needs to be installed at this time. As discussed in Orange-19, the current pipeline has sufficient capacity to handle the requested increase.

D. FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION CENTRAL DISTRICT

***CENTRAL FDEP-A.1*—Page 3-56, Part 3.6—The Department understands that all waste streams produced by Unit B addition and coal gasification project will be discharged into existing treatment /reuse system. All treated wastewater and blowdown from cooling tower will be discharged in to an on site system. Please provide discharge location, wastewater characterization and outfall location at each receiving pond. Indicate if the receiving pond is lined or unlined. OUC has been asked to provide a site plan showing all outfall locations in the past.**

Response

The cooling tower blowdown will go to the wastewater basin. The low volume wastewater (from floor drains, washdowns, etc.) will go to the recycle basin. The chemical drain effluent will be directed to the neutralization basin. The recycle, wastewater, and the neutralization basin are all lined basins. The location of discharges and outfalls are shown on the site plan recently provided to FDEP Central District. Wastewater streams are characterized in the attached table.

***CENTRAL FDEP-A.2*—Page 3-49 to 51 (Sketches)—The sketches are not very legible. A large-scale sketch is needed for review. Based on what can be read from these sketches the following comments are offered:**

- ***Figure 3.5-1 indicates a (113) 42 gpm new wastewater stream from steam cycle condensate polisher to water supply pond and a (1020) 798 gpm wastewater stream from the Wastewater Treatment (Brine Plant) to the Make Up pond.***
- ***Figure 3.5-2 indicates a wastewater stream (30) to the wastewater recycle basin.***
- ***Are these new flow numbers for the addition of Unit B ONLY?***
- ***Are they combined flow numbers from Existing Facilities and new Unit B?***
- ***Are the existing wastewater streams characterization affected by the addition of Unit B and Coal gasification additions?***

Response

Enlarged versions of the referenced sketches are attached. Figure 3.5-1 is an overall Stanton Energy Center water balance, including the new Unit B. Figure 3.5-2 is a simplified water balance for Unit B only. The existing wastewater streams characterization will not be affected by the addition of Unit B.

***CENTRAL FDEP-A.3*—Please provide a simplified site plan showing all the outfall locations and receiving water ponds etc. Identify each pond by its title/name. Indicate which ponds are lined and which are unlined. Show a single line piping location for each outfall. Please provide a wastewater characterization for each discharge outfall as stated above.**

Response

The requested site plan is attached.

***CENTRAL FDEP-A.4*—Please confirm a mathematical error/typo (rating is 1848 MW, not 1846) on page 2.**

Response

The correct number is 1,848 MW.

***CENTRAL FDEP-A.5*—Please provide the information required to address the Discharge of Produced Ground Water from any Non-Contaminated Site Activity during construction activities.**

Response

Prior to construction ground water will be analyzed. Dewatering activities will be done in accordance with Section 62.621.300, Florida Administrative Code (F.A.C.).

<u>CENTRAL FDEP-A.6</u>	***The facility will discharge of domestic/sanitary wastewater via a new septic system constructed near the new unit. The facility must obtain an appropriate permit from the Orange County Health Department. OCHD will require the facility to obtain a "no objection" letter from our office.***

<u>Response</u>

The facility will follow applicable regulatory requirements to obtain the referenced permit.

<u>CENTRAL FDEP-B.1</u>	***The Solid Waste Program proposes a Monitoring Plan Implementation Schedule (MPIS) for the ash landfill at this site. The typical monitoring frequency is twice a year. Samples of ground water from monitoring wells should be analyzed for constituents found at coal gasification cleanup sites, including PAHs, VOCs, phenols, cyanide salts, and metals. Ground water contour maps will be needed to determine the best locations for monitoring wells. Since only metals have been tested in the past, there should be initial sampling for all of the nonmetal parameters. A copy of ground water monitoring data should be sent to the Central District solid waste program.***

<u>Response</u>

Gasification ash will be subjected to a controlled test analyzing for the constituents listed. OUC will work with FDEP to identify the appropriate monitoring plan based on the results of this test. Gasification ash is not similar to the material at manufactured gas plant (MGP) cleanup sites. MGP facilities produced large amounts of tars, which present the vast majority of environmental concerns from these sites. Because of the operating conditions of the Transport Gasifier, tar production is almost zero. Any tar produced will not be contained in the gasification ash, but will be processed with the syngas.

***CENTRAL FDEP-C.1*—Fill/Clearing in Wetlands—Submit a complete Environmental Resource Permit application, including Sections A, C and E, for all proposed work on the subject project.**

Response

An environmental resource permit (ERP) application containing Sections A, C, and E with conceptual design data has been submitted (copy attached). As allowed under Section 62-17.665, F.A.C., more detailed design information for the Stanton Unit B transmission line will be submitted at a later date for post-certification monitoring review.

***CENTRAL FDEP-C.2*—Wetland Questions—Please provide a scaled fully dimensioned plan view drawing, to include the following:**

a) area to be filled and cleared as it currently exists and as proposed.
b) differentiate cross hatch for fill, cleared, wetland areas
c) dimensions of the proposed crosshatch area
d) legend to all cross hatched areas
e) acreage of proposed impacts
f) cross section location (north to south and east to west)
g) turbidity barrier location and type.

Response

An ERP application containing Sections A, C, and E with conceptual design data has been submitted. As allowed under Section 62-17.665, F.A.C., more detailed design information for the Stanton Unit B transmission line will be submitted at a later date for post-certification monitoring review.

<u>*CENTRAL FDEP-C.3*</u>—	***Please provide detailed cross section drawings of the project in a north-south and east-west direction. Please include the following in the cross section:*** ***a) dimensions to features in the section (including to the toe of slope)*** ***b) slope to the fill areas (horizontal : vertical)*** ***c) demonstrate turbidity barrier types and location*** ***d) cross hatch wetland, cleared, and fill areas*** ***e) provide a legend for the cross hatch areas*** ***f) stabilization for the side slopes*** ***g) existing and proposed elevation within the fill area*** ***h) identify all existing and proposed activities.***

<u>Response</u>

An ERP application containing Sections A, C, and E with conceptual design data has been submitted. As allowed under Section 62-17.665, F.A.C., more detailed design information for the Stanton Unit B transmission line will be submitted at a later date for post-certification monitoring review.

<u>*CENTRAL FDEP-C.4*</u>—	***Please describe any avoidance and minimization measures used to reduce the amount of wetland impacts on site. These considerations include, but are not limited to, design modifications to reduce or eliminate adverse impacts to wetlands, the degree of impact to wetlands and other surface waters caused by the proposed structure, and whether the impacts can be mitigated.***

<u>Response</u>

An ERP application containing Sections A, C, and E with conceptual design data has been submitted. As allowed under Section 62-17.665, F.A.C., more detailed design information for the Stanton Unit B transmission line will be submitted at a later date for post-certification monitoring review.

CENTRAL FDEP-C.5*—Provide complete details to your mitigation plan to offset the proposed wetland impacts. Your mitigation proposal will be reviewed and verified to the proper mitigation criteria. Once appropriate mitigation has been determined, the Department will request applicable mitigation documentation.

Response

An ERP application containing Sections A, C, and E with conceptual design data has been submitted. As allowed under Section 62-17.665, F.A.C., more detailed design information for the Stanton Unit B transmission line will be submitted at a later date for post-certification monitoring review.

CENTRAL FDEP-C.6*—Please set up an onsite meeting with the Department to review the wetland line. The area should be flagged prior to setting up the meeting. Be sure all areas proposed for work have been reviewed for wetlands using 62-340, F.A.C.

Response

A meeting is being arranged to review the proposed transmission line.

CENTRAL FDEP-D.1*—Provide engineering drawings and stormwater calculations to demonstrate that the existing stormwater management system has the capacity to treat and attenuate the runoff from the proposed project in accordance with 40C-42, F.A.C.

Response

The attached calculations were submitted with the SCA for Unit A. The detention basin was sized to handle the stormwater runoff from the Unit A and Unit B area. The attached grading and drainage drawing has been marked to show the drainage areas as they corresponding to the calculations and explanation below.

The 9-acre pond is located north of the units. The power block is located on the east side of the area and occupies 27.3 acres, and the fuel oil containment areas are in the southwest corner and occupy 4.9 acres. These areas include 41.2 acres of impervious surface. The remaining 19.8 acres will be vegetated.

Following St. Johns River Water Management District (SJRWMD) and FDEP design criteria, the pond must handle the greater volume of 1 inch of runoff for the entire site, or 2.5 inches of runoff for the impervious area. As shown in the calculation, the 2.5-inch runoff of impervious area dictates a permanent pool volume of 373,890 cubic feet (ft^3) is required, and 734,254 ft^3 is provided.

E. ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
Letter from James Hollingshead (SJRWMD)
to Hamilton Oven (FDEP),
Dated March 31, 2006

SJRWMD-1—***On Page 3-47 and 3-48 of the Supplemental Site Certification Application it states that "The addition of the IGCC unit at Stanton will require a somewhat greater supply of treated effluent. OUC is working with Orange County to amend the existing cooling water supply agreement to obtain the additional water needed for Unit B." Please provide a timeframe for amending the cooling water supply agreement. The District will need to be provided with a copy of the amended agreement once it has been executed. [Paragraphs 10.3(a)(b)(c)(d), Applicant's Handbook Consumptive Uses of Water (February 15, 2006) (A.H.)]***

Response

Orange County has committed to provide the additional treated effluent necessary for Stanton Unit B via a letter of intent dated October 24, 2004, from Michael Chandler. A copy of this letter is attached. Discussions between Orange County and OUC regarding the revised agreement are ongoing. A copy of the revised agreement will be forwarded to SJRWMD upon execution.

SJRWMD-2—***Please provide the anticipated dewatering groundwater volumes and project duration and demonstrate that the dewatering activities associated with the construction of the Unit B plant will not cause or contribute to flood damage. [Paragraphs 10.2 (n); 10.3 (i), A.H.]***

Response

Ground water volumes resulting from Unit B dewatering activities are expected to be similar to those encountered during construction of Unit A, which, before construction, were estimated to be 1 million gallons. All such ground water will be handled through existing on-site systems and will not be discharged from the site. Therefore, it is not anticipated that the dewatering activities associated with construction will cause or contribute to flooding.

F. FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
E-mail from Lee Martin (FDEP) to Richard Tedder (FDEP)
Dated April 4, 2006

FDEP E-MAIL-1—Page 3-58, Section 3.7.1, Solid Wastes, the narrative indicates the gasification ash will be conditioned with water and disposed of in the on site permitted landfill. The narrative states compatibility tests were performed and revealed no incompatibility with clay or synthetic liners but no certified test results, description of test methods, and quality assurance requirements were provided. The narrative also states the gasification ashmeets all regulatory requirements for nonhazardous materials but no test results were provided. Does the on site landfill permit have to be modified to accept this new waste stream?

Response

The original Stanton Energy Center Conditions of Certification allow for the disposal of ash in the on-site landfill. Prior to disposing of gasification ash in the landfill, the existing Waste Management Plan will be amended to include gasification ash disposal.

Gasification ash is non-hazardous by definition under the Bevill Amendment. Further, the attached toxicity characteristic leaching procedure (TCLP) test results confirm that the ash does not exhibit the characteristics of hazardous waste.

FDEP E-MAIL-2—Page 4-7, section 4.3, Groundwater Impacts, the project states construction dewatering is not expected to impact the surficial aquifer, will the dewatering have any impact on the adjacent landfill? Groundwater collected as a result of dewatering will be discharged in the existing stormwater management system, has the groundwater been sampled for potential contamination? If groundwater has been impacted is the stormwater system lined? If the stormwater system is not lined how will the impacted groundwater be managed?

Response

Please refer to the response to question FDEP-A.5.

FDEP E-MAIL-3—Page 5-5, Section 5.3.2, Groundwater Impacts, the project states the gasification ash and sulfur will be disposed in the on site landfill and any new cell will have a pozzatec material as a liner, does the current liner and any proposed liner system meet the Chapter 62-701 requirements? How is leachate managed in the current on site landfill?

Response

Yes, the current landfill meets the requirements of Chapter 62-701, F.A.C. Per Section 62-701.330, F.A.C., Landfill Permit Requirements, Sections 62-701.400-420 shall not apply to any solid waste disposal unit for which construction is completed prior to the later of the dates specified in paragraph (b) of this subsection (May 27 and November 27, 2001). Such solid waste disposal unit may be operated until filled to its permitted or modified design dimensions, which, if such a unit is lined, may include any future vertical expansion over the liner in accordance with Section 62-701.430, F.A.C.

Section 62-701.400, F.A.C., addresses liner and leachate collection systems as they pertain to landfill construction requirements. As such, the current liner, and the proposed liner system (which is similar to the existing one) meet the Chapter 62-701, F.A.C., requirements, by virtue of the fact that the landfill's completion of construction date was prior to the latter of the dates specified in Rule 62-701.330(1), paragraph (b), F.A.C., (i.e., November 27, 2001).

Improper surface drainage control in and around the landfill could result in water ponding, thereby contributing to deterioration of the working surface and leachate generation.

Surface water runoff from the combustion waste landfill area is controlled with a drainage system consisting of interceptor channels, flumes, surface drainage channels, and bench drains. Surface water runoff from the areas adjacent to the active storage area, will be diverted around the landfill area by diversion berms and diversion channels. The surface water runoff collection system diverts surface water runoff from the landfill. This system includes drainage channels along the perimeter of the landfill, bench drains at appropriate intervals on the slopes and surface drainage channels on the crest. Fabri-form (concrete)-lined flumes convey runoff from the landfill crest and benches to the drainage channels.

Surface water runoff from active areas within the landfill is collected and conveyed to the landfill runoff collection pond. The runoff collection system associated with the waste disposal operation has the capability of being phased with the construction of the landfill, and the flexibility of re-routing various areas once soil cover has been placed on them.

The surface water drainage system is operative throughout the entire development of the combustion waste landfill, thereby minimizing construction problems and negative impacts on the environment.

Leachate is also managed through the use of a 5-foot (ft) thick base of enhanced material, and a 5-ft thick enhanced material cap. The permeability coefficient of the enhanced material is 5×10^{-6} centimeters per second (cm/sec) or less.

Attachment FDEP-5

Syngas Basis for CT Performance Guarantees	
Fuel	**Volume**
CH_4	2.21
CO	23.74
CO_2	7.03
H_2	12.05
H_2O	1.02
N_2	53.93
Minor Components	(PPM)
COS	1
HCN	79
HCL	24
HF	0.4
H_2S	4
NH_3	67
Fuel Bound Nitrogen	146

Emissions Guarantees

Natural Gas

Measurement	Guaranteed Value	Load Range	Ambient Range °F
NOx @ 15% O_2 (ppmvd)	25	50-100%	19-100
CO (ppmvd)	25	60-100%	19-100
UHC (ppmvw)	7	60-100%	19-100
VOC (ppmvw)	1.4	60-100%	19-100

Syn Gas

Measurement	Guaranteed Value	Load Range	Ambient Range °F
NOx @ 15% O_2 (ppmvd)	40*	50-100%	19-100
CO (ppmvd)	25	75-100%	19-100
UHC (ppmvw)	7	75-100%	19-100
VOC (ppmvw)	1.4	75-100%	19-100

Blended Syn & Natural Gas

Measurement	Guaranteed Value	Load Range	Ambient Range °F
NOx @ 15% O_2 (ppmvd)	40*	50-100%	19-100
CO (ppmvd)	25	75-100%	19-100
UHC (ppmvw)	7	75-100%	19-100
VOC (ppmvw)	1.4	75-100%	19-100

* Assumes the thermal NOx generation of 15 ppm and organic NOx contribution (NH_3 & HCN) of 25 ppm in exhaust at 15% O_2.

Attachment FDEP-21

GE Energy

Air Emissions Terms, Definitions and General Information

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GER-4249 (08/05)

CONTENTS

Introduction

The main objective of this summary is to provide a clear definition of common terms regarding emissions, and also to provide background information on some of the frequently asked questions regarding GE emissions guarantees.

The document has been divided into sections that comprise the various air emissions that may be covered in GE emissions estimates or guarantees. Information is provided on the definition of various pollutants, recommended test methods for measurement and explanation of GE emissions estimates and guarantee requirements, along with any references for additional background information.

PM-10 and PM Emissions

1. Definition

a. For gas turbines, particulate matter (PM) emissions are assumed equal to PM-10 emissions.

b. PM-10 emissions are defined as particulate matter emissions that are less than ten (10) microns in diameter.

c. PM-10 emissions, as defined by US EPA, include filterable (front half) and condensable (back half) emissions.

d. GE believes that PM-10 emissions from natural gas combustion are essentially zero (no emissions from the combustion process itself). GE believes that the reported levels in the gathered data are due to non-combustion factors, which include test sampling and construction debris.

e. PM-10 emissions from oil-fired turbines are dependent on the amount of ash, sulfur and impurities in the fuel.

f. On oil-fired turbines, PM-10 emissions increase with increasing exhaust flow rate.

g. PM-10 emissions from NG combustion are difficult to demonstrate; emissions test take at least three (3) hours of sampling per test run.

i) Filterable Emissions:

(a) Filterable emissions are emissions that exit the stack in either solid or liquid state, and omits any condensable.

(b) Filterable emissions are referred to as front half emissions or non-condensable emissions (the solid portion captured in the front half of the sampling train and on the filter).

(c) Front half emissions are quantified using US EPA Method 5 or 5B.

(d) Reported front-half PM results from combustion turbines using US EPA Method 5/5B generally include:

   (i) Airborne PM that passes through the gas turbine inlet air filters.

   (ii) Particulate matter (inert solids) in the fuel gas supply.

   (iii) Airborne construction debris.

   (iv) Metallic rust or oxidation products.

   (v) Measurement (Method 5 or 5B) artifacts.

ii) Condensable Emissions:

(a) Condensable PM is the portion of PM emissions that exit the stack in gaseous form and condense in the cooler ambient air to form particulate matter. These emissions are most likely from liquid hydrocarbons, sulfates that are unaccounted for in the fuel analysis, and/or fluids used in the manufacture of the turbine.

(b) Condensable emissions are referred to as back half emissions (the portion that is captured in the back half of the sampling train).

(c) Condensable emissions include organic and inorganic emissions.

(d) Condensable emissions are measured using US EPA Method 202.

(e) Reported back-half condensable matter results using US EPA Method 202 may contain:

(i) Sulfates even without an SCR system.

(ii) Unburned fuel hydrocarbons, which agglomerate to form particles.

(iii) Possible other undefined condensables.

(iv) Formation of ammonium sulfates from the SCR system, which in a combined cycle application will accelerate the corrosion of the heat recovery steam generator (HRSG) tubes downstream from the catalyst.

2. Test Methods

a. Use all the test methods and procedures recommended in GEK-28172 with particular attention to the following:

i) For front-half PM use US EPA Methods 5 (hot box temperature > dew point of H_2SO_4), 5B (for non-sulfuric acid PM-10), or 201A (for PM-10).

ii) Use US EPA Method 19 for exhaust flow determination, which in turn is used to determine lb/hr PM, as indicated in GEK-28172.

iii) For back half/condensable PM use US EPA Method 202, including the post-test nitrogen purge to eliminate possible SO_2.

iv) Sample a minimum exhaust-gas volume of 125 dry standard cubic feet (dscf) (3.5 standard cubic meters (scm)) per test run.

v) Use of an emissions test firm agreed to by GE and the customer.

vi) A gas turbine (GT) compressor wash is highly recommended prior to PM-10 testing.

vii) It is recommended that ambient air particulates be minimized during testing. That includes minimizing site dust if construction is not complete, and delaying testing if crop burning is taking place.

b. No continuous emissions monitoring systems (CEMS) have been approved by the US EPA for measurement that can reliably measure particulate matter mass on a mass per unit time (i.e., lbs/hr) or concentration basis. Continuous opacity monitoring systems (COMS) measure percent opacity only.

VOC Emissions

1. Definition

a. VOC (volatile organic compounds) emissions are total hydrocarbon emissions (THC), or unburned hydrocarbons (UHC), excluding methane and ethane.

b. For natural gas fuel combustion, GE estimates VOC emissions are at 20% of UHC emissions; for distillate oil fuel combustion, the VOC emissions are 50% of UHC emissions.

c. Since VOC emissions include non-ethane, non-methane hydrocarbons, they include hazardous air pollutants (HAPs).

2. Test Methods

a. Follow test procedures per GEK-28172.

b. VOC emissions are measured using a combination of US EPA Method 25A and US EPA Method 18.7.2 (on-line flame ionization detector [FID] working in tandem with a gas chromatography [GC]). The methane and ethane emissions per Method 18.7.2 are subtracted from the Method 25A results.

c. GE does not suggest US EPA Method 18.7.1, which is an integrated bag sample. This method can introduce considerable error.

d. Equivalent molecular weight of methane is used in the calculations (use methane as the calibration gas for Method 25A to enhance analyzer response. Both total UHC and non-methane/non-ethane VOC guarantees are expressed as methane).

e. GE does not recommend CEMS for measurement of VOCs.

NO_x Emissions

1. Definition

a. Nitrogen oxides (NO_x) emissions include NO and NO_2. From gas turbines NO_x is predominately NO (for purpose of reporting, NO_2 is used as the mass reference for NO_x).

b. NO_x emissions are due to thermal NO_x from combustion and fuel bound nitrogen (FBN). In the case of natural gas, fuel bound nitrogen is assumed to be negligible, and all NO_x emissions are assumed to be thermal NO_x.

c. The FBN (organic NO_x) is the amount of nitrogen present in the fuel that is oxidized via the combustion process to NO_x. Typically, a credit is allowed up to the maximum limit of the FBN in the fuel (in the US per US EPA standard).

d. CEMS are available for monitoring NO_x emissions on a continuous, on-line basis.

2. Test Methods

a. Follow test procedures per GEK-28172.

b. Emissions testing for NO_x is determined using US EPA Method 20, with a chemiluminescent-type NO_x analyzer per Method 7E.

c. Oxygen should be sampled simultaneously with all NO_x measurements per Method 3A, for correction of NO_x to 15% O_2.

d. FBN in distillate oil is quantified by ASTM D4629, which is based on a combustion/chemiluminescence method.

CO Emissions

1. Definition

a. Carbon monoxide (CO) emissions are a measure of combustion completion as higher values of CO indicate more incomplete combustion (less oxidation) of CO to CO_2.

b. CO is typically low due to the high combustion temperatures and the thermal efficiency of the unit.

c. An oxidation catalyst in the exhaust duct can be used to reduce CO emissions by converting CO in the exhaust gas to CO_2 through reaction with O_2 ($2CO + O_2 \rightarrow 2CO_2$). They operate best with gas temperatures of 850°F to 1100°F (the operating range of a CO oxidation catalyst is 600°F to 1400°F). Most of GE's newer, advanced-combustion gas turbines should not require a CO oxidation catalyst.

d. Material for oxidation catalysts can be sensitive to the sulfur in the fuel. Typically platinum catalysts are used for fuels with sulfur, and a combination of platinum and palladium is used for non-sulfur fuel applications.

2. Test Methods

a. Follow test procedures per GEK-28172.

b. Sampling for CO is the same as for NO_x, normally with the same line feeding the different instruments.

c. CEMS are available for continuous monitoring of CO emissions.

Sulfur Oxide (SO_x) Emissions

1. Definition

a. All sulfur emissions in a gas turbine are caused by the combustion of sulfur introduced into the turbine by the fuel (most common source), air, or injected steam or water.

b. SO_x emissions include SO_2 and SO_3 emissions.

c. SO_x emissions are typically quantified as SO_2 emissions (vast majority of SO_x emissions).

d. SO_3 combines with water vapor in the exhaust to form sulfuric acid mist.

e. SO_2 to SO_3 emissions conversion as a result of the gas turbine combustion process is estimated at 5% to 10%, which is based on gathered emissions data; additional emissions conversions added for SCR (2%) and catalytic oxidizer controls (10% to 35%).

f. Control of SO_x emissions typically requires limiting the sulfur content of the fuel.

2. Test Methods

a. SO_x emissions should be determined based on the fuel flow rate and the fuel sulfur content. Refer to GEK-28172 for more information.

b. CEMS are available for measurement of SO_2 emissions.

HAP Emissions

1. Definition

a. HAPs are hazardous air pollutants identified by the US EPA in 40 CFR 61.

b. HAPs include both organic and inorganic compounds in gaseous and solid form.

c. Organic HAPs are mostly categorized with VOCs.

d. HAPs are different from toxic pollutants identified by state and local agencies. Typically, toxic emissions include additional compounds/pollutants than what are defined as HAPs by the US EPA. HAPs are typically a subset of the toxic pollutants identified by the state and local organizations.

e. Each state typically has its own toxic air pollutant (TAP) list and regulations.

f. Emissions data indicate that formaldehyde (CH_2O) is the primary HAP from gas turbines (both natural gas-fired and distillate oil-fired applications).

g. HAP emissions reduction is required by the proposed Maximum Achievable Control Technology (MACT) rule which applies to ALL stationary equipment located at major sources (40 CFR Part 63).

i) Applicability:

(a) US EPA has issued a stay for lean premix gas-fired turbines and diffusion flame gas-fired turbines (Federal Register Vol. 60, No. 159, August 18, 2004).

(b) For gas turbines, HAP emissions are very low and formaldehyde is the primary HAP.

(c) Formaldehyde is considered as a "surrogate" for other HAPs for stationary gas turbines, which means it is an indication to the level and presence of HAPs.

ii) MACT Requirements:

(a) The MACT formaldehyde limit is 91 pbbvd at 15% O_2.

(b) "Pending the outcome of US EPA's proposal to delete these subcategories from the source category list (68 FR 18338, April 7, 2004), US EPA is staying the effectiveness of the emissions and operating limitations in the stationary combustion turbines NESHAP for new sources in the lean premix gas-fired turbines and diffusion flame gas-fired turbines subcategories."

(c) The MACT limit applies to stationary lean-premix and diffusion-flame combustion turbines where all turbines at the site fire oil more than 1,000 hours per year.

(d) The Gas Turbine Association and GE continue to work with the US EPA regarding the stay and delisting petition, including the applicability to oil-fired units, as noted in (c).

2. Test Methods

a. Modified CARB (California Air Resource Board) Method 430 should be used for formaldehyde testing, with modifications as outlined in GEK-28172.

b. US EPA Method 321: This method has not been demonstrated reliably for emission levels less than 50 ppb.

Ammonia Emissions

1. Definition

a. Ammonia (NH_3) emissions are a result of the use of SCR catalysts for NO_x control.

b. With an SCR, ammonia is injected into the gas turbine exhaust gas stream to promote a chemical reaction with NO_x in the presence of a catalyst.

c. The ammonia that does not react with NO_x is referred to as "ammonia slip" which represents ammonia emissions.

d. Ammonia slip is expected to increase for low NO_x exhaust streams (7FA DLN units), because the NO_x molecules available to react with the ammonia molecules are much fewer.

e. Ammonia slip is also expected to increase as the catalyst bed ages.

f. With sulfur-bearing fuels, ammonia injection causes the formation of ammonium sulfate ($(NH_4)2SO_4$) and ammonium bisulfate (NH_4HSO_4).

g. The ammonium sulfates and ammonium bisulfates are referred to as "ammonium salts" or "ammonium sulfates."

h. The ammonium bisulfate causes rapid corrosion of the HRSG heat transfer surfaces and downstream metal surfaces.

i. Both of the ammonium compounds (ammonium salts) cause plugging and fouling of the catalyst surface, inhibiting the rate of NO_x reduction even with low-sulfur distillate oil (0.05%S) and aviation fuel. This plugging increases pressure drop, reduces heat transfer, and increases PM-10 emissions.

j. The rate of deposition of ammonium salts on the HRSG and downstream metal surfaces is dependent on the concentrations of ammonia and SO_3 in the exhaust and the duration of operation with sulfur-bearing fuels.

2. Test Methods

a. GE has established a preference for the use of on-site sampling and analysis plus calculations in accordance with the industry procedure of indophenol absorptiometrics to determine ammonia slip emissions, as outlined in GEK-28172.

b. There is currently no approved US EPA protocol for direct, continuous sensing of ammonia. Continuous emissions monitoring of NH_3 is accomplished using NO_x analyzers as an indicator of NH_3 levels.

Start-up/Shut-down (SU/SD) Emissions

1. Definition

a. Historically startup, shutdown (SU/SD) and malfunction emissions have been exempt from regulation.

b. SU/SD emissions are becoming more of an issue in permitting – largely driven by the US EPA Guideline Document to States to Include SU/SD in their SIP (State Implementation Plans).

c. Basic startup definition is not standardized. As an Original Equipment Manufacturer (OEM), GE recommends "ignition to emissions compliance" as a standard startup definition. Startup times will vary depending on a cold, warm or hot start.

d. Focus has incorrectly been on volumetric (ppm) measurements, which reach very high levels; however, the duration of these excursions is very brief and the airflows are transiently well below steady state values. This is why volumetric measurements are not representative of the total emissions for SU/SD. Measurements, reporting and permits for SU/SD emissions are recommended in mass (i.e., pounds) per event (lbs/event).

e. SU/SD emissions levels vary depending on hot, warm, and cold starts.

f. SU/SD emissions are impacted by plant operating conditions (loading limits, hold points etc.).

g. For combined cycle applications, use GE recommended startup sequence (including recommended hold points) to optimize emissions.

h. As NO_x and other emissions are driven lower with new technologies, SU/SD become a larger percent of a smaller total number.

i. Lack of standardized regulatory guidelines and methodology for reasonable, reliable measurements and reporting hinders the entire permitting process.

j. GE is currently developing a model for optimizing SU/SD emissions and is conducting emissions testing to better estimate SU/SD emissions.

2. Test Methods

a. No formal or approved test protocol currently exist for SU/SD quantification.

b. Gaseous SU/SD emissions (NO_x and CO) may be estimated with conventional methods as long as proper analyzers capable of measuring the anticipated emission levels are used. In particular:

i) Integrate measured ppm with exhaust flow rate to determine lbs/event values.

ii) Volumetric (ppm) data may vary widely (typically two orders of magnitude or more) and will require the use of multiple analyzers and ranges.

iii) Transient airflows, exhaust composition (O_2) and temperature also complicate measurements.

iv) Response time (especially via CEMS) and/or test methodology may limit the ability to accurately represent the transient nature of SU/SD emissions.

GE Emissions Estimates and Guarantees

1. GE emissions guarantees are based on statistical representation of prior data.

2. Emissions estimates and guarantees are offered in units of mass per event (i.e., lbs/hr) or concentration (mg/Nm^3), depending on customer needs.

3. As applicable, emissions estimates and guarantees must include any contribution of fired HRSG/duct burner emissions when this equipment is present.

4. PM emissions guarantees are offered at base load operations only, reflecting a worst-case scenario.

5. For fuels containing sulfur, the PM emissions estimates must account for the contribution of sulfuric acid mist emissions and/or sulfates or the estimate must specifically exclude them, as is GE's preference.

6. For cases including oxidation catalysts and SCR, the contribution of the CO catalyst to SO_3 formation, which leads to additional ammonium salts formation, will be accounted for in the PM and PM-10 emissions estimates or specifically excluded, as is preferable to GE.

7. Additional requirements for sites with a PM guarantee:
   a. Inspect and clean exhaust of any and all loose debris. Wipe exhaust down to prevent metal weepage from stainless steel being airborne.
   b. Inspect the HRSG and check for any tube spacers left in the HRSG. Thoroughly clean out the HSRG.
   c. Operate the gas turbine for at least 300 fired hours prior to particulate testing.
   d. Run the gas turbine for 3 to 4 hours at base load (or until all wheelspace temperatures have stabilized) prior to particulate testing.
   e. Visually inspect and clean the inlet filter house prior to a test.
8. Subpart GG ISO correction for NO_x is NOT applicable to DLN units (Note: DLN is only applicable to gas-fired units) or to GE's diffusion flame units with the Mark V or Mark VI controller.
9. Special requirements for CO emissions may be necessary in regions designated as "non-attainment" for CO.
10. GE does not offer guarantees for SO_x/SO_2 emissions. SO_x emissions are considered "pass through" and estimated as SO_2 emissions based on the sulfur content of the fuel and air pass through.
11. When combined with ammonia, sulfur bearing fuels cause the formation of ammonium sulfate and ammonium bisulfate salts, even with low sulfur distillate oil (0.05%S) and aviation fuel.
12. In combined cycle applications, ammonium sulfur salts cause:
   a. Rapid corrosion of boiler tube material, resulting in an increased pressure drop and reduced heat transfer.
   b. Increased pressure drop and reduced heat transfer.
   c. Increased PM emissions (also in the case of simple cycle applications).
13. When ammonia injection is used in the HRSG:
   a. Limit sulfur content in the fuel to very low levels (< 0.05% by wt.).
   b. Limit the amount of excess ammonia available to react with sulfur oxides.
   c. Paint critical internal stack sections.
   d. Increase HRSG feedwater temperature to reduce condensation (keep temperature greater than the dewpoint of sulfuric acid mist).
   e. Allow provisions for cleaning, draining, and drying of the HRSG tubes.
14. Do not use SCR on GTs with sulfur-bearing fuels as their primary fuel.
15. If a sulfur-bearing fuel is used as a backup fuel, the first recommendation is to turn the SCR and ammonia injection off, or if the SCR is needed to reduce NO_x, limit the operation on the sulfur-bearing fuel to 240 hrs/yr.
16. Proper catalyst materials must be used for high sulfur content fuels, otherwise catalyst poisoning will occur reducing catalyst effectiveness and increasing emissions.
17. It is GE's experience that formaldehyde is the only HAP that requires permitting.
18. Currently, no guarantees are extended for formaldehyde or other HAPs emissions.
19. Currently GE does not guarantee SU/SD emissions for any pollutants.

Additional References

1. "Support for Elimination of Oxidation Catalyst Requirement for GE PG7241FA DLN Combustion Turbines." GER-4213

2. "Gas Turbine NO_x Emissions Approaching Zero – Is it Worth the Price?" GER-4172

3. "SCR Experience With Sulfur-Bearing Fuels," under Tab 8 – Environmental Engineering of GE's Combined Cycle Plant Design Guideline.

Attachment FDEP-25

FDEP Question 25
Emission Rate Summary Table

Parameter	Units	Syngas				Natural Gas			
		1-Syn	5-Syn	9-Syn	7-Syn	1-NG	6-NG	11-NG	9-NG
Load	%	100	100	100	75	100	100	100	50
Evaporative Cooling	On / Off	Off	On	On	Off	Off	On	On	Off
Ambient Temperature	°F	20	70	95	70	20	70	95	70
Power Output	Gross MW	328	328	319	261	256	236	223	137
	Net MW	283	283	269	223	249	229	215	130
PM/PM_{10}	lb/hr	31.0	30.8	29.4	24.6	18.2	18.2	18.2	18.1
	lb/10^6 Btu[1]	0.013	0.013	0.013	0.013	0.0094	0.0104	0.0108	0.0163
	lb/MWh (gross)	0.094	0.094	0.092	0.094	0.071	0.077	0.082	0.132
	lb/MWh (net)	0.109	0.109	0.109	0.110	0.073	0.079	0.085	0.139
SO_2	lb/hr	35.8	35.6	33.9	28.3	1.2	1.0	1.0	0.7
	ppmvd @ 15% O_2	2.7	2.7	2.7	2.7	0.12	0.12	0.12	0.12
	lb/10^6 Btu[1]	0.015	0.015	0.015	0.015	0.0006	0.0006	0.0006	0.0006
	lb/MWh (gross)	0.109	0.108	0.106	0.109	0.0045	0.0044	0.0045	0.0048
	lb/MWh (net)	0.126	0.126	0.126	0.127	0.0047	0.0046	0.0047	0.0051
H_2SO_4	lb/hr	5.5	5.4	5.2	4.3	0.18	0.16	0.15	0.10
	lb/10^6 Btu[1]	0.0023	0.0023	0.0023	0.0023	0.000091	0.000091	0.000091	0.000091
	lb/MWh (gross)	0.017	0.017	0.016	0.017	0.00069	0.00068	0.00069	0.00074
	lb/MWh (net)	0.019	0.019	0.019	0.019	0.00071	0.00070	0.00072	0.00078
NO_x (Phase I)	lb/hr	188.5	188.3	181.7	148.6	35.1	31.6	30.4	19.6
	ppmvd @ 15% O_2	20.0	20.0	20.0	20.0	5.0	5.0	5.0	5.0
	lb/10^6 Btu[1]	0.079	0.079	0.080	0.079	0.018	0.018	0.018	0.018
	lb/MWh (gross)	0.575	0.574	0.570	0.569	0.137	0.134	0.136	0.143
	lb/MWh (net)	0.666	0.665	0.676	0.666	0.141	0.138	0.142	0.151
NO_x (Phase II)	lb/hr	113.1	113.0	109.0	89.2	N/A	N/A	N/A	N/A
	ppmvd @ 15% O_2	12.0	12.0	12.0	12.0	N/A	N/A	N/A	N/A
	lb/10^6 Btu[1]	0.047	0.048	0.048	0.047	N/A	N/A	N/A	N/A
	lb/MWh (gross)	0.345	0.344	0.342	0.342	N/A	N/A	N/A	N/A
	lb/MWh (net)	0.400	0.399	0.405	0.400	N/A	N/A	N/A	N/A
CO	lb/hr	89.7	90.7	87.8	72.9	87.7	79.0	75.7	56.4
	ppmvd @ 15% O_2	15.6	15.8	15.9	16.1	20.5	20.5	20.4	23.6
	lb/10^6 Btu[1]	0.038	0.038	0.039	0.039	0.045	0.045	0.045	0.051
	lb/MWh (gross)	0.274	0.276	0.275	0.279	0.342	0.335	0.340	0.412
	lb/MWh (net)	0.317	0.320	0.326	0.327	0.352	0.345	0.352	0.434
VOC	lb/hr	15.0	15.4	15.0	12.4	16.4	15.0	14.4	10.3
	ppmvd @ 15% O_2	4.6	4.7	4.8	4.8	6.7	6.8	6.8	7.6
	lb/10^6 Btu[1]	0.0063	0.0065	0.0067	0.0065	0.0085	0.0085	0.0086	0.0093
	lb/MWh (gross)	0.046	0.047	0.047	0.047	0.064	0.063	0.065	0.075
	lb/MWh (net)	0.053	0.055	0.056	0.055	0.066	0.065	0.067	0.080

[1] Based on heat input (HHV) to the gasifiers (for syngas) and the combustion turbine (for natural gas).

Sources: ECT, 2006
SCS, 2006.

Attachment EPA-4

Table A-7. Stanton Unit B CT/HRSG
Hazardous Air Pollutants - Syngas

Revised May 3, 2006

Parameter	Units	CT		DB
		100%, 20 °F	100%, 70 °F	100%
Maximum Heat Input (HHV):	10^6 Btu/hr	2,384	2,371	532
Maximum Annual Hours:	hrs/yr		8,760	8,760

Pollutant	CT Emission Factor[1] (lb/10^6 Btu)	DB Emission Factor[2,3] (lb/10^6 Btu)	Maximum CT (lb/hr)	Maximum DB (lb/hr)	CT & DB Total[4] (lb/hr)	CT & DB Total[5] TPY
1,3-Butadiene	N/A	N/A	N/A	N/A	N/A	N/A
2-Methylnaphthalene	3.6E-07	N/A	8.58E-04	N/A	8.58E-04	3.74E-03
Acenaphthylene	2.6E-08	N/A	6.20E-05	N/A	6.20E-05	2.70E-04
Acetaldehyde	1.8E-06	N/A	4.29E-03	N/A	4.29E-03	1.87E-02
Acrolein	N/A	N/A	N/A	N/A	N/A	N/A
Antimony	4.0E-06	N/A	9.53E-03	N/A	9.53E-03	4.15E-02
Arsenic	2.1E-06	N/A	5.01E-03	N/A	5.01E-03	2.18E-02
Benzaldehyde	2.9E-06	N/A	6.91E-03	N/A	6.91E-03	3.01E-02
Benzene	4.4E-06	2.1E-06	1.05E-02	1.09E-03	1.16E-02	5.05E-02
Benzo(a)anthracene	2.3E-09	N/A	5.48E-06	N/A	5.48E-06	2.39E-05
Benzo(e)pyrene	5.5E-09	N/A	1.31E-05	N/A	1.31E-05	5.71E-05
Benzo(g,h,l)perylene	9.5E-09	N/A	2.26E-05	N/A	2.26E-05	9.86E-05
Beryllium	9.0E-08	N/A	2.15E-04	N/A	2.15E-04	9.35E-04
Cadmium	2.9E-06	N/A	6.91E-03	N/A	6.91E-03	3.01E-02
Carbon Disulfide	4.5E-05	N/A	1.07E-01	N/A	1.07E-01	4.67E-01
Chromium	2.7E-06	N/A	6.44E-03	N/A	6.44E-03	2.80E-02
Cobalt	5.7E-07	N/A	1.36E-03	N/A	1.36E-03	5.92E-03
Ethylbenzene	N/A	N/A	N/A	N/A	N/A	N/A
Formaldehyde	1.7E-05	7.4E-05	4.05E-02	3.91E-02	7.96E-02	3.48E-01
Manganese	3.1E-06	N/A	7.39E-03	N/A	7.39E-03	3.22E-02
Mercury[6]	9.1E-07	N/A	2.17E-03	N/A	2.17E-03	9.45E-03
Naphthalene	4.0E-07	6.0E-07	9.53E-04	3.18E-04	1.27E-03	5.55E-03
Nickel	3.9E-06	N/A	9.30E-03	N/A	9.30E-03	4.05E-02
Polycyclic Aromatic Hydrocarbons (PAHs)	N/A	N/A	N/A	N/A	N/A	N/A
Propylene Oxide	N/A	N/A	N/A	N/A	N/A	N/A
Selenium	2.9E-06	N/A	6.91E-03	N/A	6.91E-03	3.01E-02
Toluene	N/A	3.3E-06	N/A	1.77E-03	1.77E-03	7.76E-03
Xylene	N/A	N/A	N/A	N/A	N/A	N/A
Maximum Individual HAP						0.5
Total HAPs						1.2

Notes:

CT = Combustion Turbine

DB = Duct Burner

[1] Emission factors from *A Study of Toxic Emissions from a Coal-Fired Gasification Plant*

[2] - EPA AP-42, Table 1.4-3, March 1998.

[3] - EPA AP-42, Table 1.4-4, March 1998.

[4] - Based on baseload and 20F temperature.

[5] - Based on baseload and 70F temperature.

[6] - Mercury emission factor basedon a maximum mercury concentration from testing samples of PRB coal and an expected mercury control system remo val efficiency of 90 percent.

Sources: ECT, 2006
SCS, 2006.

Attachment ORANGE-1

Table 2.3-19. Orlando Area Ambient Air Quality Data—1995 through 2005 ~~2000 through 2004~~(Continued, Page 1 of 6)

Pollutant	Site Location: County	Site Location: City	Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (ug/m³): 1st High	2nd High	Arithmetic Mean	St*n***r**	Percent of Standard
PM_{10}	Orange	Winter Park	Morris Boulevard	120952002	23	306	2000	24-hour	61	46	39		150*	30.7
							2001	24-hour	60	46	41		150*	30.7
							2002	24-hour	60	33	30		150*	22.0
							2003	24-hour	61	30	28		150*	20.0
							2004	24-hour	56	41	27		150*	27.3
							2005	24-hour	61	58	34		150*	38.7
							2000	Annual	61			21	50†	42.0
							2001	Annual	60			20	50†	40.0
							2002	Annual	60			17	50†	34.0
							2003	Annual	61			18	50†	36.0
							2004	Annual	56			18	50†	36.0
							2005	Annual	61			17	50†	34.0
PM_{10}	Orange	Orlando	North Primrose Avenue	120951004	19	295	2000	24-hour	60	37	37		150*	24.7
							2001	24-hour	59	48	43		150*	32.0
							2002	24-hour	61	35	31		150*	23.3
							2003	24-hour	61	56	47		150*	37.3
							2004	24-hour	59	41	36		150*	27.3
							2005	24-hour	61	52	34		150*	34.7
							2000	Annual	60			21	50†	42.0
							2001	Annual	59			22	50†	44.0
							2002	Annual	61			18	50†	36.0
							2003	Annual	61			20	50†	40.0
							2004	Annual	59			19	50†	38.0
							2005	Annual	61			18	50†	36.0
PM_{10}	Orange	Orlando	Sheriff's Department	120950007	24	278	2000	24-hour	61	48	44		150*	32.0
							2001	24-hour	61	53	50		150*	35.3
							2002	24-hour	61	41	38		150*	27.3
							2003	24-hour	59	39	37		150*	26.0
							2000	Annual	61			27	50†	54.0
							2001	Annual	61			23	50†	46.0

Table 2.3-19. Orlando Area Ambient Air Quality Data—1995 through 2005 ~~2000 through 2004~~(Continued, Page 2 of 6)

Pollutant	Site Location		Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (ug/m^3)				
	County	City								1st High	2nd High	Arithmetic Mean	St*n***r**	Percent of Standard
							2002	Annual	61			23	50†	46.0
							2003	Annual	59			21	50†	42.0
PM_{10}	Brevard	Titusville	Tico Airport	120090004	37	84	2000	24-hour	48	35	34		150*	23.3
							2001	24-hour	357	96	55		150*	64.0
							2002	24-hour	334	66	38		150*	44.0
							2003	24-hour	354	170	79		150*	113.3
							2004	24-hour	334	61	46		150*	40.7
							2005	24-hour	290	60	48		150*	40.0
							2000	Annual	48			17	50†	34.0
							2001	Annual	357			19	50†	38.0
							2002	Annual	334			17	50†	34.0
							2003	Annual	354			19	50†	38.0
							2004	Annual	334			17	50†	34.0
							2005	Annual	290			16	50†	32.0
$PM_{2.5}$	Orange	Winter Park	Morris Boulevard	120952002	23	306	2000	24-hour	345	35	34		65*	53.8
							2001	24-hour	336	61	41		65*	93.8
							2002	24-hour	353	26	25		65*	40.0
							2003	24-hour	357	23	22		65*	35.4
							2004	24-hour	326	28	26		65*	43.1
							2005	24-hour	345	46	42		65*	70.8
							2000	Annual	345			11.9	15†	79.3
							2001	Annual	336			10.7	15†	71.3
							2002	Annual	353			9.5	15†	63.3
							2003	Annual	357			9.3	15†	62.0
							2004	Annual	326			9.9	15†	66.0
							2005	Annual	345			9.7	15†	64.7
$PM_{2.5}$	Orange	Orlando	North Primrose Avenue	120951004	19	295	2000	24-hour	353	35	34		65*	53.8
							2001	24-hour	353	52	41		65*	80.0
							2002	24-hour	349	30	27		65*	46.2
							2003	24-hour	345	23	21		65*	35.4

Table 2.3-19. Orlando Area Ambient Air Quality Data—1995 through 2005 ~~2000 through 2004~~ (Continued, Page 3 of 6)

Pollutant	Site Location: County	Site Location: City	Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (ug/m^3): 1st High	2nd High	Arithmetic Mean	St*n***r**	Percent of Standard
							2004	24-hour	307	38	26		65*	58.5
							2005	24-hour	343	45	42		65*	69.2
							2000	Annual	353			12	15†	80.0
							2001	Annual	353			10.9	15†	72.7
							2002	Annual	349			9.7	15†	64.7
							2003	Annual	345			9.4	15†	62.7
							2004	Annual	307			10.1	15†	67.3
							2005	Annual	343			9.8	15†	65.3
SO_2	Orange	Winter Park	Morris Boulevard	120952002	23	306	2000	3-hour	8,420	109.7	70.5		1,300‡	8.4
							2001	3-hour	8,401	83.6	70.5		1,300‡	6.4
							2002	3-hour	8,571	34.0	28.7		1,300‡	2.6
							2003	3-hour	8,647	31.3	28.7		1,300‡	2.4
							2004	3-hour	8,324	36.6	23.5		1,300‡	2.8
							2005	3-hour	8,493	28.7	23.5		1,300‡	2.2
							2000	24-hour	8,420	34.0	23.5		365‡	9.3
							2001	24-hour	8,401	36.6	20.9		365‡	10.0
							2002	24-hour	8,571	13.1	13.1		365‡	3.6
							2003	24-hour	8,647	15.7	10.4		365‡	4.3
							2004	24-hour	8,324	13.1	13.1		365‡	3.6
							2005	24-hour	8,493	10.4	7.8		365‡	2.9
							2000	Annual	8,420			7.8	80†	9.8
							2001	Annual	8,401			5.2	80†	6.5
							2002	Annual	8,571			2.6	80†	3.3
							2003	Annual	8,647			2.6	80†	3.3
							2004	Annual	8,324			2.6	80†	3.3
							2005	Annual	8,493			2.6	80†	3.3
NO_2	Orange	Winter Park	Morris Boulevard	120952002	23	306	2000	Annual	8,470			22.5	100†	22.5
							2001	Annual	8,495			22.5	100†	22.5
							2002	Annual	8,485			20.7	100†	20.7
							2003	Annual	8,437			20.7	100†	20.7

Table 2.3-19. Orlando Area Ambient Air Quality Data—1995 through 2005 ~~2000 through 2004~~ (Continued, Page 4 of 6)

Pollutant	Site Location County	Site Location City	Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (ug/m^3) 1st High	2nd High	Arithmetic Mean	Standard	Percent of Standard
							2004	Annual	8,418			18.8	100†	18.8
							2005	Annual	8,569			16.9	100†	16.9
CO	Orange	Winter Park	Morris Boulevard	120952002	23	306	2000	1-hour	8,542	8,571	8,571		40,000‡	21.4
							2001	1-hour	8,438	9,143	3,086		40,000‡	22.9
							2002	1-hour	8,619	4,343	4,000		40,000‡	10.9
							2003	1-hour	8,667	2,971	2,629		40,000‡	7.4
							2004	1-hour	8,460	2,743	2,743		40,000‡	6.9
							2005	1-hour	8,596	2,514	2,400		40,000‡	6.3
							2000	8-hour	8,542	5,371	2,743		10,000‡	53.7
							2001	8-hour	8,438	2,400	2,286		10,000‡	24.0
							2002	8-hour	8,619	3,200	2,857		10,000‡	32.0
							2003	8-hour	8,667	1,714	1,714		10,000‡	17.1
							2004	8-hour	8,460	1,829	1,829		10,000‡	18.3
							2005	8-hour	8,596	2,286	2,057		10,000‡	22.9
	Orange	Orlando	Orange Avenue	120951005	21	289	2000	1-hour	8,619	5,143	5,143		40,000‡	12.9
							2001	1-hour	8,572	4,800	4,343		40,000‡	12.0
							2002	1-hour	8,530	5,143	5,029		40,000‡	12.9
							2003	1-hour	8,551	3,886	3,657		40,000‡	9.7
							2004	1-hour	8,596	4,686	3,086		40,000‡	11.7
							2005	1-hour	8,674	9,829	8,914		40,000‡	24.6
							2000	8-hour	8,619	2,971	2,971		10,000‡	29.7
							2001	8-hour	8,572	2,743	2,400		10,000‡	27.4
							2002	8-hour	8,530	3,314	2,857		10,000‡	33.1
							2003	8-hour	8,551	2,286	2,286		10,000‡	22.9
							2004	8-hour	8,596	2,171	2,057		10,000‡	21.7
							2005	8-hour	8,674	5,943	2,971		10,000‡	59.4
										[ppm]			[ppm]	
O_3	Orange	Winter Park	Morris Boulevard	120952002	23	306	1995	1-hour‡‡	358	N/A			0.12**	N/A
							1996	1-hour‡‡	358	N/A			0.12**	N/A
							1997	1-hour‡‡	363	0.096			0.12**	80.0
							1998	1-hour‡‡	351	0.099			0.12**	82.5
							1999	1-hour‡‡	240	0.100			0.12**	83.3

Table 2.3-19. Orlando Area Ambient Air Quality Data—1995 through 2005 ~~2000 through 2004~~(Continued, Page 5 of 6)

Pollutant	Site Location: County	Site Location: City	Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (ug/m³): 1st High	2nd High	Arithmetic Mean	St*n***r**	Percent of Standard
							2000	1-hour‡‡	242	0.106			0.12**	88.3
							2001	1-hour‡‡	228	0.105			0.12**	87.5
							2002	1-hour‡‡	237	0.105			0.12**	87.5
							2003	1-hour‡‡	244	0.100			0.12**	83.3
							2004	1-hour‡‡	233	0.095			0.12**	79.2
							2005	1-hour‡‡	244	0.095			0.12**	79.2
										[ppm]			[ppm]	
							1995	8-hour***	354	N/A			0.08††	N/A
							1996	8-hour***	354	N/A			0.08††	N/A
							1997	8-hour***	360	0.075			0.08††	88.3
							1998	8-hour***	349	0.080			0.08††	91.5
							1999	8-hour***	238	0.083			0.08††	93.6
							2000	8-hour***	240	0.084			0.08††	97.1
							2001	8-hour***	224	0.081			0.08††	97.4
							2002	8-hour***	234	0.078			0.08††	95.5
							2003	8-hour***	242	0.076			0.08††	92.4
							2004	8-hour***	227	0.075			0.08††	90.2
							2005	8-hour***	243	0.078			0.08††	90.0
										[ppm]			[ppm]	
	Orange	Orlando	Winegard Road	120950008	21	262	1995	1-hour‡‡	363	N/A			0.12**	N/A
							1996	1-hour‡‡	363	N/A			0.12**	N/A
							1997	1-hour‡‡	360	0.106			0.12**	88.3
							1998	1-hour‡‡	344	0.109			0.12**	90.8
							1999	1-hour‡‡	224	0.115			0.12**	95.8
							2000	1-hour‡‡	245	0.108			0.12**	90.0
							2001	1-hour‡‡	241	0.101			0.12**	84.2
							2002	1-hour‡‡	228	0.101			0.12**	84.2
							2003	1-hour‡‡	244	0.094			0.12**	78.3
							2004	1-hour‡‡	163	0.094			0.12**	78.3
							2005	1-hour‡‡	242	0.099			0.12**	82.5
										[ppm]			[ppm]	
							1995	8-hour***	354	N/A			0.08††	N/A
							1996	8-hour***	354	N/A			0.08††	N/A
							1997	8-hour***	360	0.079			0.08††	92.7
							1998	8-hour***	349	0.082			0.08††	94.8
							1999	8-hour***	238	0.083			0.08††	95.8

Table 2.3-19. Orlando Area Ambient Air Quality Data—1995 through 2005 ~~2000 through 2004~~(Continued, Page 6 of 6)

Pollutant	Site Location: County	Site Location: City	Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (ug/m³): 1st High	2nd High	Arithmetic Mean	St*n***r**	Percent of Standard
							2000	8-hour***	245	0.083			0.08††	97.8
							2001	8-hour***	241	0.079			0.08††	96.2
							2002	8-hour***	225	0.077			0.08††	93.8
							2003	8-hour***	243	0.075			0.08††	90.8
							2004	8-hour***	161	0.074			0.08††	88.9
							2005	8-hour***	243	0.078			0.08††	89.3
Lead	Orange	Winter Park	Morris Boulevard	120952002	23	306	1994 to 96	24-hour	182	0.0	0		1.5†	0.0
	Orange	Orlando	Sheriff's Department	120950007	24	278	1994 to 96	24-hour	182	0.00	0		1.5†	0.0

Note: N/A = not available.

*98th percentile.

†Arithmetic mean.

‡2nd high.

**4th highest day with hourly value exceeding standard over a 3-year period.

††4th highest daily 8-hour concentration averaged over a 3-year period..

‡‡4th highest daily 1-hour maximum concentration over a 3-year period.

***3-year average of the 4th highest 8-hour concentration.

Sources: FDEP, 2005.
EPA, 2005
ECT, 2005.

Attachment ORANGE-10

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [x] Rule [ ] Other

3. Allowable Opacity:
Normal Conditions: ~~20~~5 % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:
EPA Reference Method 9

5. Visible Emissions Comment:

Rule 62-296.320(4)(b), F.A.C.

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other

3. Allowable Opacity:
Normal Conditions: % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

5. Visible Emissions Comment

Attachment CENTRAL FDEP-A.1

(1) 0950137-01

FIGURE 3.5-3.

DETAILED UNIT B WATER BALANCE DIAGRAM

Source: SCS, 2006.

ECT
Environmental Consulting & Technology, Inc.

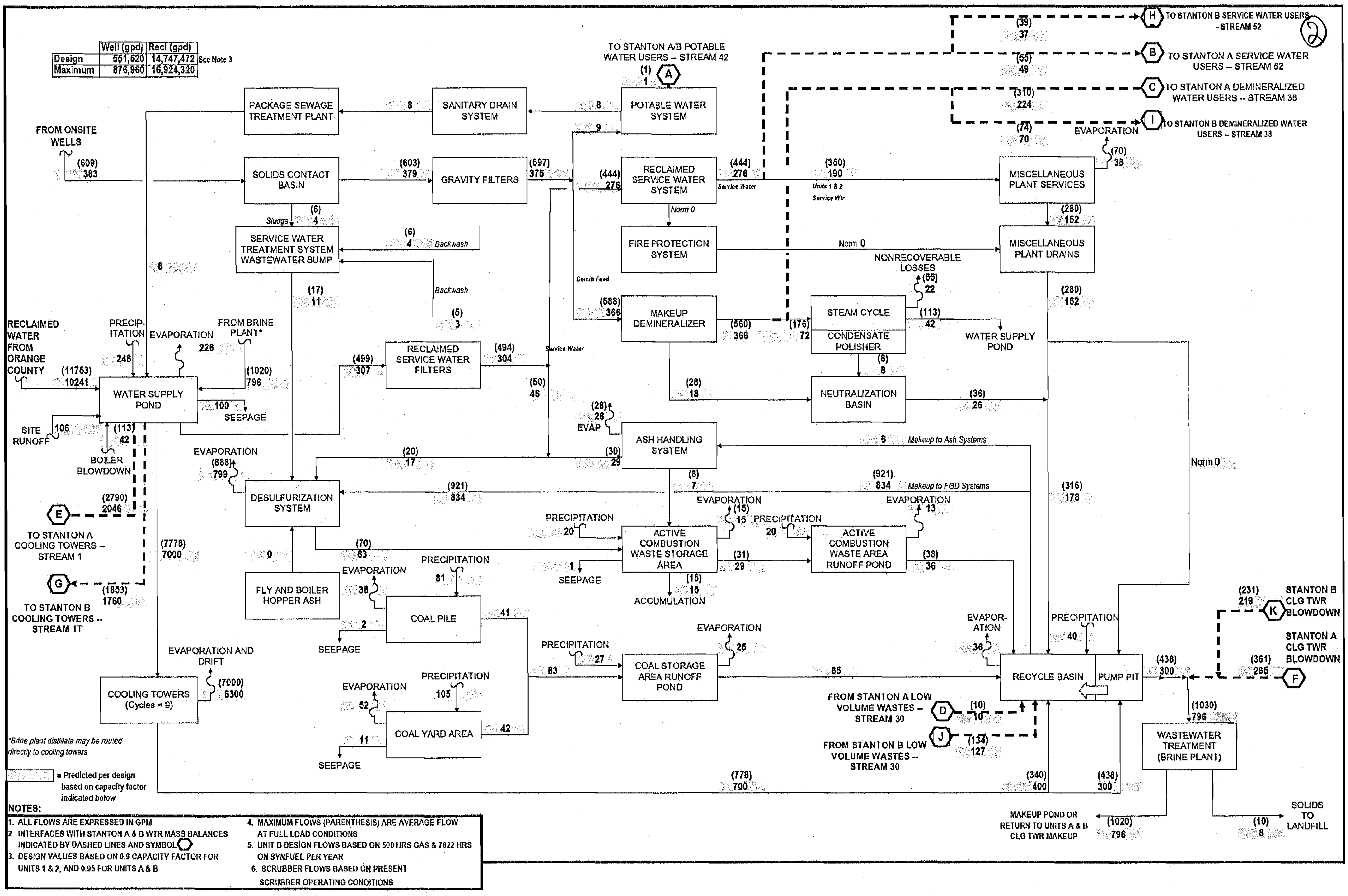

FIGURE 3.5-1.

OVERALL STANTON WATER BALANCE DIAGRAM, INCLUDING UNIT B

Source: B&V, 2006.

ECT

Environmental Consulting & Technology, Inc.

③

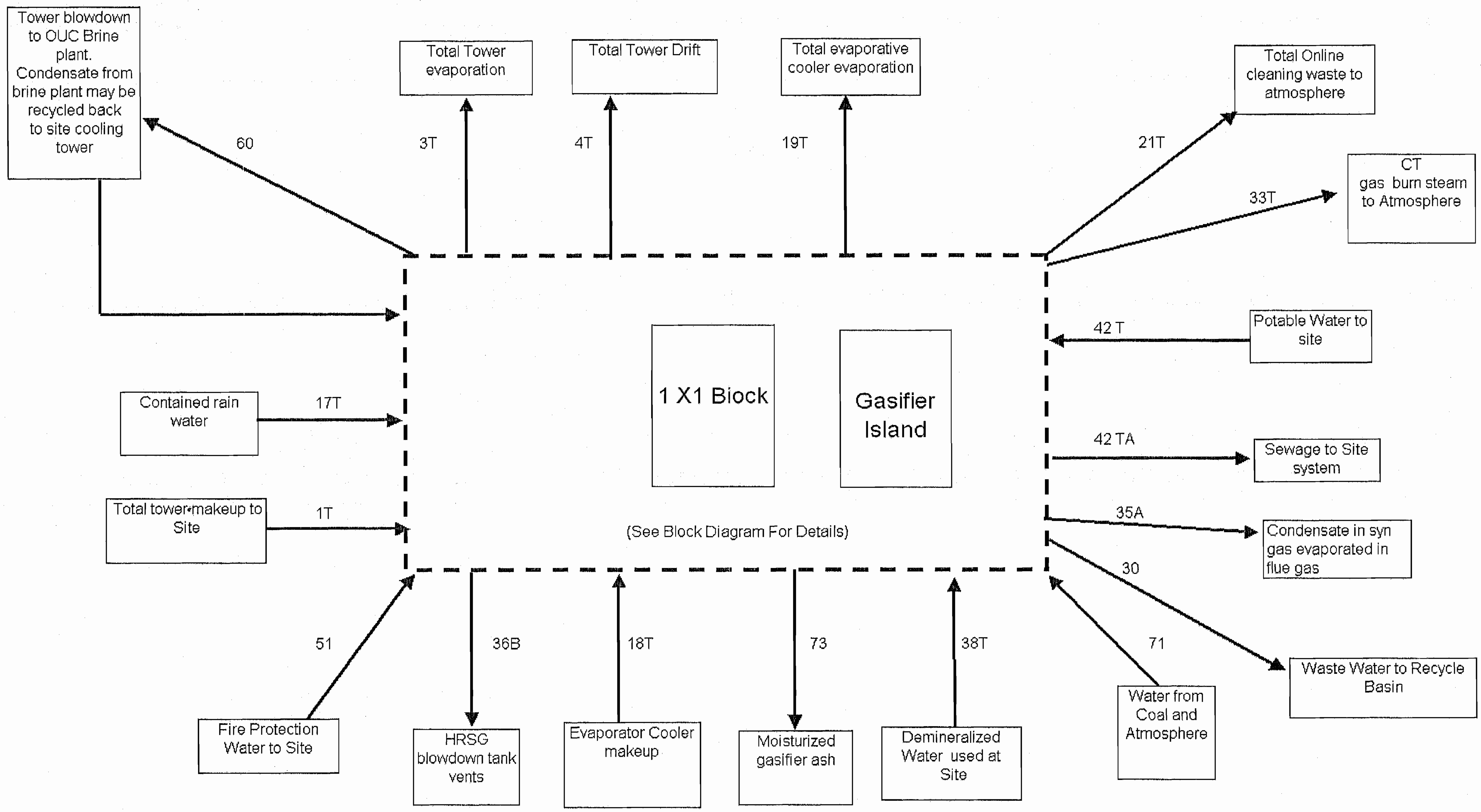

FIGURE 3.5-2.

SIMPLIFIED UNIT B WATER BALANCE DIAGRAM

Source: SCS, 2006.

ECT
Environmental Consulting & Technology, Inc.

Attachment CENTRAL FDEP-A.3

\\Newton\Projects\ouc\Stanton\mxd\Stanton_aerial.mxd das
DATE: 05/01/2006

Management Areas and Monitoring Wells at OUC Stanton Energy Center

CH2MHILL

Attachment CENTRAL FDEP-C.1

YOUNG VAN ASSENDERP, P.A.

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George Ann C. Bracko
Executive Director

May 2, 2006

Hamilton S. Oven
Administrator
Siting Coordination Office
Department of Environmental Protection
2800 Blair Stone Road, Room 649
Tallahassee, Florida 32399

Re: Orlando Utilities Commission Stanton Energy Center Unit B Supplemental Site Certification Application - Application for Environmental Resource Permit

Dear ~~Mr. Oven~~ Buck:

On behalf of Orlando Utilities Commission (OUC) and Southern Power Company-Orlando Gasification LLC (SPC-OG), we are pleased to submit our Application for Environmental Resource Permit (ERP) in conjunction with our submittal of the Supplemental Site Certification Application for the proposed Stanton Energy Center Integrated Gasification Combined Cycle (IGCC) Unit B (Stanton Unit B) on February 17, 2006. Specifically, submission of this information is in response to Question C.1., DEP-Central District Questions, as set out in the Department's Determination of Insufficiency dated April 10, 2006.

Five copies of the ERP are being submitted simultaneously to DEP's Central District office.

We look forward to working with you and your staff as this application continues to progress through the certification process. If you have questions concerning this application, please do not hesitate to call me.

Sincerely,

Tasha

Tasha O. Buford

TOB/kdr
Enclosures
cc: DEP – Central District

FORM #: 62-343.900(1)
FORM TITLE: JOINT ENVIRONMENTAL RESOURCE PERMIT APPLICATION
DATE: March 26, 2004

JOINT APPLICATION FOR

ENVIRONMENTAL RESOURCE PERMIT/

AUTHORIZATION TO USE SOVEREIGN SUBMERGED LANDS/

FEDERAL DREDGE AND FILL PERMIT

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION/
WATER MANAGEMENT DISTRICTS/
U.S. ARMY CORPS OF ENGINEERS

TABLE OF CONTENTS
FOR ERP APPLICATION FORM PACKAGE

SECTION A

FOR AGENCY USE ONLY	
ACOE Application #	DEP/WMD Application #
Date Application Received	Date Application Received
Proposed Project Lat.	Fee Received $
Proposed Project Long.	Fee Receipt #

PART 1:
Are any of the activities described in this application proposed to occur in, on, or over wetlands or other surface waters?
☒ yes ☐ no
Is this application being filed by or on behalf of a government entity or drainage district? ☐yes ☒no

PART 2:

A. Type of Environmental Resource Permit Requested (check at least one). See Attachment 2 for thresholds and descriptions.

☐ Noticed General - include information requested in Section B.
☐ Standard General (Single Family Dwelling) - include information requested in Sections C and D.
☐ Standard General (all other Standard General projects) - include information requested in Sections C and E.
☐ Individual (Single Family Dwelling) - include information requested in Sections C and D.
☒ Individual (all other Individual projects) - include information requested in Sections C and E.
☐ Conceptual - include information requested in Sections C and E.
☐ Mitigation Bank Permit (construction) - include information requested in Sections C and F. (If the proposed mitigation bank involves the construction of a surface water management system requiring another permit defined above, check the appropriate box and submit the information requested by the applicable section.)
☐ Mitigation Bank (conceptual) - include information requested in Sections C and F.

B. Type of activity for which you are applying (check at least one)

☒ Construction or operation of a new system, other than a solid waste facility, including dredging or filling in, on or over wetlands and other surface waters.
☐ Construction, expansion or modification of a solid waste facility.
☐ Alteration or operation of an existing system which was not previously permitted by a WMD or DEP.
☐ Modification of a system previously permitted by a WMD or DEP.
Provide previous permit numbers:_____

☐ Alteration of a system ☐ Extension of permit duration
☐ Abandonment of a system ☐ Construction of additional phases of a system
☐ Removal of a system

C. Are you requesting authorization to use Sovereign Submerged Lands?
☐yes ☒no
(See Section G and Attachment 5 for more information before answering this question.)

D. For activities in, on,or over wetlands or other surface waters, check type of federal dredge and fill permit requested:
☒Individual ☐Programmatic General ☐General
☐Nationwide ☐Not Applicable

E. Are you claiming to qualify for an exemption? ☐yes ☒no
If yes, provide rule number if known. _____

FORM #: 62-343.900 (1)
FORM TITLE: JOINT ENVIRONMENTALRESOURCE PERMIT APPLICATION
DATE: March 26, 2004

PART 3: A. OWNER(S) OF LAND	B. ENTITY TO RECEIVE PERMIT (IF OTHER THAN OWNER)
Name **Fredrick F. Haddad, Jr.**	Name
Title and Company **Vice Pres. Power Resources, Orlando Utilities Commission**	Title and Company
Address **500 South Orange Avenue**	Address
City, State, Zip **Orlando, Florida 32802**	City, State, Zip
Telephone and Fax **(407) 658-6444 (phone); (407) 275-4120 (fax)**	Telephone and Fax
E-mail Address: (optional)	E-mail Address: (optional)

C. AGENT AUTHORIZED TO SECURE PERMIT	D. CONSULTANT (IF DIFFERENT FROM AGENT)
Name	Name
Title and Company	Title and Company
Address	Address
City, State, Zip	City, State, Zip
Telephone and Fax	Telephone and Fax
E-mail Address: (optional)	E-mail Address: (optional)

PART 4: (Please provide metric equivalent for federally funded projects):

A. Name of Project, including phase if applicable: **Stanton Unit B**

B. Is this application for part of a multi-phase project? ☐ Yes ☒ No

C. Total applicant-owned area contiguous to the project? 3,445 ac.; 1,394 ha.

D. Total area served by the system: 5.8 ac.; 2.4 ha.

E. Impervious area for which a permit is sought: 1.49 ac.; 0.60 ha.

F. Volume of water that the system is capable of impounding: 0 ac. ft.; 0 m^3

G. What is the total area of work in, on, or over wetlands or other surface waters?
3.97 ac.; **1.61** ha.; **172,933.2** sq. ft.; 16,066.02 sq. m.

H. Total volume of material to be dredged: **0** yd^3; **0** m^3

I. Number of new boat slips proposed: 0 wet slips; 0 dry slips

PART 5:

Project location (use additional sheets if needed):
County(ies)**Orange**

Section(s) **13**	Township **23 South**	Range **31 East**
Section(s) **18,**	Township **23 South**	Range **32 East**
Section(s)	Township	Range

Land Grant name, if applicable:

Tax Parcel Identification Number: _____

Street Address Road or other location: **Stanton Energy Center, 5100 Alafaya Trail**

City, Zip Code, if applicable: **Orlando, 32802**

PART 6: Describe in general terms the proposed project, system, or activity.

One new transmission line is proposed to connect the new Stanton Unit B with OUC's existing Stanton Substation No. 17. The proposed transmission line will be constructed using single-pole tubular steel structures or direct embedded concrete poles designed to support a 230-kV circuit. The total length of the transmission line is approximately 3,200 feet and is located entirely within the existing Stanton Energy Center.

PART 7:

A. If there have been any pre-application meetings, including on-site meetings, with regulatory staff, please list the date(s), location(s), and names of key staff and project representatives.
Pre-application/Site Certification Application meeting in January 2006. Site wetlands inspection with USACE (Jeff Collins) in January 2006.

B. Please identify by number any MSSW/Wetland Resource/ERP/ACOE Permits pending, issued or denied for projects at the location, and any related enforcement actions.

Agency	Date	No.\Type of Application	Action Taken
_____	_____	_____	_____
_____	_____	_____	_____
_____	_____	_____	_____

C. Note: The following information is required for projects proposed to occur in, on or over wetlands that need a federal dredge and fill permit or an authorization to use state owned submerged lands. Please provide the names, addresses and zip codes of property owners whose property directly adjoins the project (excluding application) and/or (for proprietary authorizations) is located within a 500 ft. radius of the applicant's land. Please attach a plan view showing the owner's names and adjoining property lines. Attach additional sheets if necessary.

REFER TO FIGURE A1

1.
Orange County BCC
P.O. Box 1393
Orlando, FL 32802

2.
Morgran Co., Inc.
15 McMurrich Street
Suite 1104
Toronto, Canada M5R3

3.
Estate of Redditt, John Cecil
4414 Calm Water Court
Orlando, FL 32817

4.
St. John's River Water Management District
P.O. Box 1429
Palatka, FL 32178

5.
Smith, W. Roger
601 Lake Harbor Circle
Orlando, FL 32809

6.
TIITF/DOC
3900 Commonwealth Boulevard
Tallahassee, FL 32399

7.
International Corporate Park, LLC
301 E. Pine Street
Suite 125
Orlando, FL 32801

8.

PART 8:

A. By signing this application form, I am applying, or I am applying on behalf of the applicant, for the permit and any proprietary authorizations identified above, according to the supporting data and other incidental information filed with this application. I am familiar with the information contained in this application and represent that such information is true, complete and accurate. I understand this is an application and not a permit, and that work prior to approval is a violation. I understand that this application and any permit issued or proprietary authorization issued pursuant thereto, does not relive me of any obligation for obtaining any other required federal, state, water management district or local permit prior to commencement of construction. I agree, or I agree on behalf of the applicant, to operate and maintain the permitted system unless the permitting agency authorizes transfer of the permit to a responsible operation entity. I understand that knowingly making any false statement or representation in this application is a violation of Section 373.430, F.S. and 18 U.S.C. Section 1001.

Denise M. Stalls
Typed/Printed Name of Applicant (If no Agent is used) or Agent (If one is so authorized below)

Denise M Stalls 5/2/06
Signature of Applicant/Agent Date
Vice President, Environmental Affairs
(Corporate Title if applicable)

AN AGENT MAY SIGN ABOVE ONLY IF THE APPLICANT COMPLETES THE FOLLOWING:

B. I hereby designate and authorize the agent listed above to act on my behalf, or on behalf of my corporation, as the agent in the processing of this application for the permit and/or proprietary authorization indicated above; and to furnish, on request, supplemental information in support of the application. In addition, I authorize the above-listed agent to bind me, or my corporation, to perform any requirements which may be necessary to procure the permit or authorization indicated above. I understand that knowingly making any false statement or representation in this application is a violation of Section 373.430, F.S. and 18 U.S.C. Section 1001.

Typed/Printed Name of Applicant	Signature of Applicant	Date

(Corporate Title if applicable)

Please note: The applicant's original signature (not a copy) is required above.

PERSON AUTHORIZING ACCESS TO THE PROPERTY MUST COMPLETE THE FOLLOWING:

C. I either own the property described in this application or I have legal authority to allow access to the property, and I consent, after receiving prior notification, to any site visit on the property by agents or personnel from the Department of Environmental Protection, the Water Management District and the U.S. Army Corps of Engineers necessary for the review and inspection of the proposed project specified in this application. I authorize these agents or personnel to enter the property as many times as may be necessary to make such review and inspection. Further, I agree to provide entry to the project site for such agents or personnel to monitor permitted work if a permit is granted.

Denise M. Stalls	Denise M Stalls	5/2/06
Typed/Printed Name of Applicant	Signature of Applicant	Date

Vice President, Environmental Affairs
(Corporate Title if applicable)

Design Water Characterization IGCC Stanton Unit B

Stream CT syn gas	normal Flow gpm	Ca ppm as element	Mg ppm as element	Na ppm as element	Fe ppm as element	Total Cations as CACO3	HCO3 ppm as element	Cl ppm as element	SO4 ppm as element	PO4 ppm as PO4	Total Anions as CACO3	Si ppm as SiO2	TOC ppm as element	Hardness ppm as CACO3	Ammonia ppm as NH3	pH as such	Suspended Solids ppm	Temperature deg. F as such
Makeup water from OUC makeup pond	1853.2	35.200	9.900	70.300	0.190	282.355	115.000	82.000	45.000	3.000	282.160	16.000	7.870	129.000	0.000	7.700	8.000	95.000
Total makeup water from OUC make pond	1853.2	35.200	9.900	70.300	0.190	282.355	115.000	82.000	45.000	3.000	282.160	16.000	7.870	129.000	0.000	7.700	8.000	95.000
Main Cooling tower makeup	1850.7	35.200	9.900	70.300	0.190	282.355	115.000	82.000	45.000	3.000	282.160	16.000	7.870	129.000	0.000	7.700	8.000	95.000
Total site main cooling tower makeup	1850.7	35.200	9.900	70.300	0.190	282.355	115.000	82.000	45.000	3.000	282.160	16.000	7.870	129.000	0.000	7.700	8.000	95.000
Circulating water pump discharge	76000.0	280.436	78.872	560.093	1.517	2249.550	916.193	653.286	358.527	23.926	2247.998	127.473	64.067	1027.730	0.046	7.800	63.740	87.000
Cooling tower blowdown	228.0	280.436	78.872	560.093	1.517	2249.550	916.193	653.286	358.527	23.926	2247.998	127.473	64.067	1027.730	0.046	7.800	63.740	113.000
Total site cooling tower blowdown	452.0	280.436	78.872	560.093	1.517	2249.550	916.193	653.286	358.527	23.926	2247.998	127.473	64.067	1027.730	0.046	7.800	63.740	113.000
Waste treatment condensate to OUC makeup pond or site tower	231.4	1.391	0.393	2.769	0.008	11.144	4.533	3.238	1.780	0.118	11.136	0.635	0.316	5.104	0.000	7.000	0.000	116.511
Makeup water to CT evaporative cooler	27.4	16.570	6.940	16.500	0.190	106.360	34.000	33.970	23.400	0.000	106.234	11.290	1.390	70.360	0.000	9.370	0.000	80.000
CT evap cooler blowdown	3.4	132.560	55.520	132.000	1.520	850.881	272.000	271.760	187.200	0.000	849.870	90.320	11.120	562.880	0.000	7.920	0.000	80.000
Oil water separator to low volume sump	5.0	0.004	0.000	0.003	0.001	0.019	0.000	0.002	0.017	0.000	0.021	0.010	0.300	0.010	0.000	11.000	0.000	80.000
Low volume waste to OUC recycle basin	127.1	3.501	0.783	0.452	3.225	21.625	0.000	4.588	0.003	0.000	6.473	0.001	1.192	11.964	939.800	7.036	0.000	113.903
Makeup to Condenser Hotwell	45.3	0.004	0.000	0.003	0.001	0.019	0.000	0.002	0.017	0.000	0.021	0.010	0.300	0.010	0.000	6.600	0.000	80.000
Makeup for losses at HRSG	45.3	0.004	0.000	0.003	0.001	0.019	0.000	0.002	0.017	0.000	0.021	0.010	0.300	0.010	0.000	6.600	0.000	80.000
HRSG Blowdown to tower	0.6	0.400	0.000	8.000	1.000	21.130	0.000	0.300	5.500	10.000	21.943	1.000	30.000	0.000	1.000	11.000	2.000	212.000
HRSG Blowdown	0.9	0.400	0.000	8.000	1.000	21.130	0.000	0.300	5.500	10.000	21.943	1.000	30.000	0.000	1.000	11.000	2.000	212.000
HRSG blowdown tank vent	0.3	0.400	0.000	8.000	1.000	21.130	0.000	0.300	5.500	10.000	21.943	1.000	30.000	0.000	1.000	11.000	2.000	212.000
Demin. water to process	*50.3*	*0.004*	*0.000*	*0.003*	*0.001*	*0.019*	*0.000*	*0.002*	*0.017*	*0.000*	*0.021*	*0.010*	*0.300*	*0.010*	*0.000*	*6.600*	*0.000*	*80.000*
Total HRSG miscellaneous losses	10.0	0.004	0.000	0.003	0.016	0.060	0.000	0.003	0.055	0.000	0.061	0.010	30.000	0.010	1.000	11.000	0.000	212.000
Panel waste to low volume sump	5.0	0.004	0.000	0.003	0.016	0.060	0.000	0.003	0.055	0.000	0.061	0.010	30.000	0.010	1.000	11.000	0.000	77.000
Potable water to block from potable water supply	17.0	16.570	6.940	16.500	0.190	106.360	34.000	33.970	23.400	0.000	106.234	11.290	1.390	70.360	0.000	9.370	0.000	80.000
Sewage to treatment from block	17.0	16.570	6.940	16.500	0.190	106.360	34.000	33.970	23.400	0.000	106.234	11.290	1.390	70.360	0.000	9.370	220.000	80.000
From existing OUC potable/service water system	44.4	16.570	6.940	16.500	0.190	106.360	34.000	33.970	23.400	0.000	106.234	11.290	1.390	70.360	0.000	9.370	0.000	80.000
Evap cooler makeup from OUC site	27.4	16.570	6.940	16.500	0.190	106.360	34.000	33.970	23.400	0.000	106.234	11.290	1.390	70.360	0.000	9.370	0.000	80.000
Total evap cooler makeup from OUC site	27.4	16.570	6.940	16.500	0.190	106.360	34.000	33.970	23.400	0.000	106.234	11.290	1.390	70.360	0.000	9.370	0.000	80.000
Solids to land fill pounds per minute	6.6	276.854	78.134	550.982	1.509	NA	902.116	644.396	354.209	23.454	NA	126.288	62.966	1015.739	0.045	NA	62.796	NA
Conc. Waste sump to OUC tower blowdown sump	231.4	278.245	78.526	553.751	1.517	2228.829	906.649	647.634	355.988	23.572	2227.285	126.923	63.283	1020.843	0.045	7.802	62.796	112.511
Gasifier CrystaSulf and sour water cleanup combined waste	*99.0*	*3.800*	*0.850*	*0.490*	*3.500*	*0.000*	*No Data*	*4.980*	*0.000*	*No Data*	*0.000*	*No Data*	*0.000*	*12.985*	*1020.000*	*7.000*	*0.000*	*120.000*
Gasifier crystafsulf makeup	2.5	35.200	9.900	70.300	0.190	0.000	115.000	82.000	45.000	3.000	0.000	16.000	7.870	129.000	0.000	7.700	8.000	95.000
Gasifier waste water sump to low volume waste sump	117.1	3.800	0.850	0.490	3.500	0.000	No Data	4.980	0.000	No Data	0.000	No Data	0.000	12.985	1020.000	7.000	0.000	120.000

Attachment CENTRAL FDEP-A.2

SECTION B

NOT APPLICABLE

INFORMATION FOR NOTICED
GENERAL ENVIRONMENTAL RESOURCE PERMITS

INSTRUCTIONS: To qualify for a Noticed General Permit (NGP) for specific activities, the project must strictly comply with all of the terms, conditions, requirements, limitations and restrictions applicable to the desired NGP. A summary of the types of NGP's available is contained in Attachment 2. Carefully review the rule section of the NGP for which you are applying to ensure that your project meets the requirements of that NGP. Please complete Section A and submit it along with the information required in this Section (on 81/2" x 11" paper).

1. Indicate the project boundaries on a USGS quad map, reduced or enlarged as necessary to legibly show the entire project. If not apparent from the quad map, provide a location map (in sufficient detail to allow a person unfamiliar with the site to find it), containing a north arrow and a graphic scale and showing the boundary of the proposed activity and Section(s), Township(s), and Range(s).

2. A legible site plan showing the following features:

a) property boundaries and dimensions
b) name and location of any adjoining public streets or roads
c) location and dimensions of all existing structures
d) label all impervious and pervious area
and indicate their size (area)
e) the direction of drainage relative to the proposed improvements (using arrows)
f) locations of all proposed works
g) permanent and temporary erosion, sedimentation and turbidity controls
h) boundaries of wetlands and other surface waters, identifying open water areas
i) boundary area and volume of all temporary and permanent earthwork, including pre and post construction grades

3. Description of wetland or aquatic habitat .

4. Construction methods and schedule.

5. Additional information that would show that you qualify for the general permit, addressing all the parameters, thresholds and conditions required in the general permit. Errors and omissions will be identified within 30 days by the processing agency.

6. Provide the rule section number of the NGP for which you are applying.

7. The construction plans and supporting calculations must be signed, sealed, and dated by an appropriate registered professional as required by the relevant statutory provisions when the design of the system requires the services of an appropriate registered professional.

SECTION C

Environmental Resource Permit Notice of Receipt of Application

Note: this form does not need to be submitted for noticed general permits.
This information is required in addition to that required in other sections of the application. Please submit five copies of this notice of receipt of application and all attachments with the other required information. Please submit all information on 8 1/2" x 11" paper.

Project Name	**Stanton Unit B**
County	**Orange**
Owner	**Orlando Utilities Commission**
Applicant:	**Orlando Utilities Commission**
Applicant's Address:	**500 South Orange Avenue, Orlando, Florida 32802**

1. Indicate the project boundaries on a USGS quadrangle map. Attach a location map showing the boundary of the proposed activity. The map should also contain a north arrow and a graphic scale; show Section(s), Township(s), and Range(s); and must be of sufficient detail to allow a person unfamiliar with the site to find it.
A project boundary map is included as Figure C1.

2. Provide the names of all wetlands, or other surface waters that would be dredged, filled, impounded, diverted, drained, or would receive discharge (either directly or indirectly), or would otherwise be impacted by the proposed activity, and specify if they are in an Outstanding Florida Water or Aquatic Preserve:
Unnamed hydric Pine Savanna and Cypress Strand wetlands occur within the transmission line corridor. These wetlands are not Outstanding Florida Waters or Aquatic Preserves.

3. Attach a depiction (plan and section views), which clearly shows the works or other facilities proposed to be constructed. Use multiple sheets, if necessary. Use a scale sufficient to show the location and type of works.
See Engineering Drawings appended to this application.

4. Briefly describe the proposed project (such as "construct dock with boat shelter", "replace two existing culverts", "construct surface water management system to serve 150 acre residential development"):
The work requested herein involves the installation of a new 230 kV electrical transmission line.

5. Specify the acreage of wetlands or other surface waters, if any, that are proposed to be filled, excavated, or otherwise disturbed or impacted by the proposed activity:

filled **1.49** ac.; **0** excavated ac.;

other impacts 2.46 ac.(clearing in forested wetlands)

6. Provide a brief statement describing any proposed mitigation for impacts to wetlands and other surface waters (attach additional sheets if necessary):
The proposed electrical transmission line will span 0.02 acres of wetlands located in a roadside ditch. Since these wetlands will remain undisturbed no mitigation measures are proposed. Mitigation for the 3.95 acres (or less) of permanent clearing/fill impacts in wetlands will be determined during post-submittal agency negotiations.

FOR AGENCY USE ONLY

Application Name:
Application Number:
Office where the application can be inspected:

Note to Notice recipient: The information in this notice has been submitted by the applicant, and has not been verified by the agency. It may be incorrect, incomplete or may be subject to change.

SECTION D

NOT APPLICABLE

INFORMATION REQUIRED FOR STANDARD GENERAL OR INDIVIDUAL ENVIRONMENTAL RESOURCE PERMIT APPLICATIONS RELATED TO A SINGLE FAMILY DWELLING UNIT

Complete this Section only if your project does not qualify for an exemption or noticed general permit. The information requested below is only for projects related to an individual, single family dwelling unit, duplex, triplex, or quadruplex which is not part of a larger common plan of development proposed by the applicant. Please contact the local office of the DEP or WMD if you are unsure whether your project would fit this description.

PLEASE SUBMIT ALL INFORMATION ON 8 1/2" by 11" PAPER

A. SITE INFORMATION

1. Directions: Provide written directions to the property.

2. Specify how the location of the proposed work is marked on site: for example, the center line of the road is flagged, string running between stakes identifies bulkhead location, etc.

B. DRAWINGS

Drawings should be of sufficient detail to clearly show the existing physical conditions of the site, and the extent, type, and location of the proposed activities. The drawings should clearly show waters/wetlands to be impacted, either temporarily or permanently. Any water/wetland areas proposed to be created, enhanced, restored, preserved, or which will remain undisturbed should be clearly identified and labeled. The following drawings are required:

1. PLAN VIEW (TOP VIEW)

This shows the work as viewed from above. A survey of the project site is very useful as a starting point for preparing plan views of the project. Include the following:

a. Applicant name, property line, north arrow and graphic scale or dimensions of proposed work on each drawing sheet.

b. Representative land elevations (spot elevations or contour lines) referred to National Geodetic Vertical Datum (NGVD), as is used on the USGS contour maps.

c. The limits of wetlands and other surface waters and the limits of open water areas in the vicinity of the proposed work. Describe how the wetland limits were determined. If there has ever been a jurisdictional declaratory statement, a formal wetland determination, a formal determination, validated informal determination, or a revalidated jurisdictional determination, provide the identifying number.

d. All proposed work, including dredging, filling or structures. Where possible, differentiate between work in open water, marshes, swamps, or tidal flats and uplands.

e. Show selected water depths in and adjacent to the project site. For dock projects, show water depths at all mooring sites. These depths should be determined at approximate mean low water (MLW) or seasonal low water. Include the approximate tidal range (the difference between approximate mean high water (MHW) elevation and approximate MLW elevation) if the project is in a tidal waterbody.

f. Label all existing structures in wetlands or other surface waters at or adjacent to the proposed activity, such as docks, bulkheads, riprap, or buildings.

g. If dredging or dewatering is involved, show the location of proposed disposal or containment sites. Include any levees, control structures or other methods for retaining or detaining return water. Also include locations of discharge sites where appropriate. (Note that a consumptive or water use permit may be required for dewatering.)

h. For piling supported structures over wetlands or other surface waters, show the entire structure. Indicate the location of any aquatic vegetation in the vicinity of the proposed structure.

i. Show distance between the most waterward point of the proposed facility and the nearest edge of any navigation channel, where appropriate. If the project is on a waterway that has a federally maintained channel, a survey may be required to establish the distance from the waterward points of the structure to the near edge of the federal channel. Also indicate the width of the waterway.

j. Clearly show the locations of all corresponding cross-sectional or profile views on the plan view drawings.

2. CROSS-SECTIONAL AND PROFILE VIEWS

The cross-sectional view should show a "cut-away" end or middle view of the project, while the profile view should show a side view as if cut length-wise. All drawings should include:

a. Applicant name and graphic horizontal and vertical scales or dimensions of the proposed work on each drawing sheet.

b. Show approximate mean or seasonal (high and low) water line elevations referenced to NGVD.

C. PROJECT DETAILS

Provide a detailed description of the proposed project, including the following:

1. The type of activity that is proposed, how the activity will be conducted, construction techniques and sequencing, including equipment to be used, and methods for moving the equipment to and from the site. For projects that involve any dredging or excavation, describe the method of excavation, the type of material to be excavated, and the disposal location for the excavated material. State whether dredged material is to be placed (either temporarily or permanently) in a wetland or other surface water. Indicate the time period any temporary structures will be in place.

2. The acreage (or square footage) of excavation and fill and differentiate between temporary and permanent work.

3. Methods for controlling turbidity (muddy water caused by erosion or work in the water).

4. Methods for stabilizing any slopes that will be created or disturbed during construction, including times expected to elapse before stabilization is performed. Describe both temporary and permanent stabilization methods, such as staked hay bales, temporary grass seed, and permanent sod.

5. If pilings or a seawall are to be installed state whether pilings and seawall slabs are to be installed by jetting or driving.

6. For fill projects, describe the source and type of fill material to be used. For activities that involve the installation of riprap , describe the source, type and size of the rocks, concrete, or other material to be used for the riprap, and how these materials are to be placed. State whether the rocks will be underlain with filter cloth.

SECTION E

INFORMATION REQUESTED FOR STANDARD GENERAL, INDIVIDUAL AND CONCEPTUAL ENVIRONMENTAL RESOURCE PERMIT APPLICATIONS NOT RELATED TO A SINGLE FAMILY DWELLING UNIT

Please provide the information requested below if the proposed project requires either a standard general, individual, or conceptual approval environmental resource permit and is not related to an individual, single family dwelling unit, duplex or quadruplex. The information listed below represents the level of information that is usually required to evaluate an application. The level of information required for a specific project will vary depending on the nature and location of the site and the activity proposed. Conceptual approvals generally do not require the same level of detail as a construction permit. However, providing a greater level of detail will reduce the need to submit additional information at a later date. If an item does not apply to your project, proceed to the next item. Please submit all information that is required by the Department on either 8 1/2 in. X 11 in. paper or 11 in. X 17 in. paper. Larger drawings may be submitted to supplement but not replace these smaller drawings.

I. Site Information

A. Provide a map(s) of the project area and vicinity delineating USDA/SCS soil types.
Figure E1 is map of the project area and vicinity delineating USDA/SCS soil types.

B. Provide recent aerials, legible for photo interpretation with a scale of 1" = 400 ft, or more detailed, with project boundaries delineated on the aerial.
Figure E2 is an aerial photograph of the project area and vicinity.

C. Identify the seasonal high water or mean high tide elevation and normal pool or mean low tide elevation for each on site wetland or surface water, including receiving waters into which runoff will be discharged. Include dates, datum, and methods used to determine these elevations.

Appendix B of the ERP application for Unit A (January 2001) provides data from monitoring wells on the Stanton Energy Center site. Additional reports (listed below) can be provided upon request.

- **i. Soil Investigation, Orlando Utilities Commission – Stanton Energy Center, Black & Veatch project No. 8927, includes Phase I Soil Investigation.**
- **ii. Laboratory Testing, Orlando Utilities Commission – Curtis H. Stanton Plant, Orlando, Florida, by Ardaman & Associates, Inc., September 10, 1980.**
- **iii. Laboratory Testing, Orlando Utilities Commission – Curtis H. Stanton Plant, Orlando, Florida, august 6, 1981, by Ardaman & Associates, Inc.**
- **iv. Laboratory and Field Materials Test Results, Orlando Utilities Commission – Stanton Energy Center Unit 2, Orlando, Florida, Black & Veatch Project No. 16805, by Universal Engineering Sciences, Inc., May 28, 1992.**

D. Identify the wet season high water tables at the locations representative of the entire project site. Include dates, datum, and methods used to determine these elevations.

Appendix B of the ERP application for Unit A (January 2001) provides data from monitoring wells on the Stanton Energy Center site. Additional reports (listed below) can be provided upon request.

- **v. Soil Investigation, Orlando Utilities Commission – Stanton Energy Center, Black & Veatch project No. 8927, includes Phase I Soil Investigation.**
- **vi. Laboratory Testing, Orlando Utilities Commission – Curtis H. Stanton Plant, Orlando, Florida, by Ardaman & Associates, Inc., September 10, 1980.**
- **vii. Laboratory Testing, Orlando Utilities Commission – Curtis H. Stanton Plant, Orlando, Florida, august 6, 1981, by Ardaman & Associates, Inc.**
- **viii. Laboratory and Field Materials Test Results, Orlando Utilities Commission – Stanton Energy Center Unit 2, Orlando, Florida, Black & Veatch Project No. 16805, by Universal Engineering Sciences, Inc., May 28, 1992.**

II. Environmental Considerations

A. Provide results of any wildlife surveys that have been conducted on the site, and provide any comments pertaining to the project from the Florida Game and Fresh Water Fish Commission and the U.S. Fish and Wildlife Service.

Wildlife surveys for the relevant areas of the site were conducted on November 9 – 11, 2005. Results are presented in Table E1. State or Federally listed wildlife species potentially occurring on the Stanton site and within the proposed transmission corridor are listed on Table E2. Table E3 lists threatened, endangered, and protected plant species that have been documented on or near the transmission corridor.

B. Provide a description of how water quantity, quality, hydroperiod, and habitat will be maintained in on-site wetlands and other surface waters that will be preserved or will remain undisturbed.

Wetlands are present in a roadside ditch located in the proposed transmission corridor. The acreage of these roadside ditch wetlands is 0.02 acres. The roadside ditch will be spanned by the proposed transmission line and, since no clearing or filling will be required, it will not be affected by construction. Water quantity and hydroperiod will be maintained in undisturbed areas by maintaining the existing drainage pattern. Water quality will be maintained during construction with appropriate erosion control best management practices to prevent sediment and construction debris from reaching wetlands adjacent to the proposed transmission line corridor. All waste materials will be removed and property disposed at reasonable intervals. Materials such as fuels and similar products will be stored appropriately to avoid spills and incidental releases to the environment. Fugitive dust emissions will be controlled with water sprays. Construction activities and personnel traffic will be confined to within the proposed transmission line corridor to maintain the integrity of adjacent habitat.

C. Provide a narrative description of any proposed mitigation plans, including purpose, maintenance, monitoring, and construction sequence and techniques, and estimated costs.

Mitigation for the 3.95 acres (or less) of permanent impacts will be determined during post-submittal agency negotiations.

D. Describe how boundaries of wetlands or other surface waters were determined. If there has ever been a jurisdictional declaratory statement, a formal wetland determination, a formal determination, a validated informal determination, or a revalidated jurisdictional determination, provide the identifying number.

From November 9 – 11, 2005, wetland ecologists conducted jurisdictional determinations within the referenced 80-ft wide transmission corridor. Wetlands were delineated using methods consistent with the a) applicable FDEP regulations (Section 62-301 and 62-340, F.A.C.) and b) Routine Onsite Determination Methods, as described in the U.S. Army Corps of Engineers (USACE) 1987 Wetlands Delineation Manual. In both cases the most current vegetative index was used. A jurisdictional wetland inspection to verify the accuracy of the wetland limits onsite is currently being scheduled with the FDEP Central District and the USACE.

All wetlands were field flagged and then recorded by a Florida registered surveying firm. A standard USACE Routine Wetland Determination Data Form was completed for each wetland type within the corridor. In addition, Wetland Rapid Assessment Procedures (WRAP) and Uniform Mitigation Assessment Method (UMAM) forms were also completed for each wetland. The referenced functional wetland analyses will be used to determine the quality/value of wetland functions lost and the amount of mitigation required to ameliorate those losses..

E. Impact Summary Tables:

1. For all projects, complete Tables 1, 2 and 3 as applicable.

2. For docking facilities or other structures constructed over wetlands or other surface waters, provide the information requested in Table 4.

3. For shoreline stabilization projects, provide the information requested in Table 5.

III. Plans

Provide clear, detailed plans for the system including specifications, plan (overhead) views, cross sections (with the locations of the cross sections shown on the corresponding plan view), and profile (longitudinal) views of the proposed project. The plans must be signed and sealed by a an appropriate registered professional as required by law. Plans must include a scale and a north arrow. These plans should show the following:

A. Project area boundary and total land area, including distances and orientation from roads or other land marks; **Refer to Figure E3.**

B. Existing land use and land cover (acreage and percentages), and on-site natural communities, including wetlands and other surface waters, aquatic communities, and uplands. Use the Florida Land Use Cover & Classification System (FLUCCS)(Level 3) for projects proposed in the South Florida Water Management District, the St. Johns River Water Management District, and the Suwannee River Water Management District and use the National Wetlands Inventory (NWI) for projects proposed in the Southwest Florida Water Management District. Also identify each community with a unique identification number which must be consistent in all exhibits.

Refer to Figure E4.

C. The existing topography extending at least 100 feet off the project area, and including adjacent wetlands and other surface waters. All topography shall include the location and a description of known benchmarks, referenced to NGVD. For systems waterward of the mean high water (MHW) or seasonal high water lines, show water depths, referenced to mean low water (MLW) in tidal areas or seasonal low water in non-tidal areas, and list the range between MHW and MLW. For docking facilities, indicate the distance to, location of, and depths of the nearest navigational channel and access routes to the channel.

Refer to Figure E5.

D. If the project is in the known flood plain of a stream or other water course, identify the following: 1) the flood plain boundary and approximate flooding elevations; and 2) the 100-year flood elevation and floodplain boundary of any lake, stream or other watercourse located on or adjacent to the site;

The proposed transmission line is outside of the 100 year floodplain.

E. The boundaries of wetlands and other surface waters within the project area. Distinguish those wetlands and other surface waters that have been delineated by any binding jurisdictional determination;

Refer to Figure E6.

F. Proposed land use, land cover and natural communities (acreage and percentages), including wetlands and other surface waters, undisturbed uplands, aquatic communities, impervious surfaces, and water management areas. Use the same classification system and community identification number used in III (B) above.

Following construction, the transmission line right-of-way will be maintained as a utility corridor for required safety, operation, and maintenance of the new line.

G. Proposed impacts to wetlands and other surface waters, and any proposed connections/outfalls to other surface waters or wetlands;

Proposed impacts to wetlands will consist of the following:
Filling 0.06 acres of cypress strand;
Filling 1.43 acres of hydric pine savanna
Clearing 0.06 acres of cypress strand
Clearing 2.40 acres of hydric pine savanna
No surface water impacts or connections are proposed.

H. Proposed buffer zones;

The transmission line is proposed entirely within Orlando Utilities Commission property; therefore, no buffer zone is proposed.

I. Pre- and post-development drainage patterns and basin boundaries showing the direction of flows, including any off-site runoff being routed through or around the system; and connections between wetlands and other surface waters;

The existing drainage patterns would remain unchanged since no stormwater control system is associated with the electric transmission line.

J. Location of all water management areas with details of size, side slopes, and designed water depths;
No stormwater control facilities are associated with the electric transmission line.

K. Location and details of all water control structures, control elevations, any seasonal water level regulation schedules; and the location and description of benchmarks (minimum of one benchmark per structure);
No stormwater control facilities are associated with the electric transmission line.

L. Location, dimensions and elevations of all proposed structures, including docks, seawalls, utility lines, roads, and buildings;

Refer to the Engineering Drawings, which are appended.

M. Location, size, and design capacity of the internal water management facilities;

No stormwater management facilities are associated with the electric transmission line

N. Rights-of-way and easements for the system, including all on-site and off-site areas to be reserved for water management purposes, and rights-of-way and easements for the existing drainage system, if any;

No rights-of-way or easements will be required for construction or operation of the electric transmission line.

O. Receiving waters or surface water management systems into which runoff from the developed site will be discharged;

Runoff would continue to drain to natural (existing) drainage patterns.

P. Location and details of the erosion, sediment and turbidity control measures to be implemented during each phase of construction and all permanent control measures to be implemented in post-development conditions;

Erosion and sediment control best management practices will be installed as necessary during construction to retard erosion and control sediment depositions in compliance with Rule 62-621.300(4), F.A.C. Silt fencing and hay bales will be used as necessary to preserve the surrounding wetland areas. Mats will be placed leading into the wet areas to provide access for the equipment needed to set the poles. Rubber tracked equipment will be used to clear the vegetation from the ROW so that the soil surface will not be disturbed. The soil surface will not be rutted or uprooted from the equipment being used and all soil being taken out from the placement of the poles will be removed from the site to an upland area.

Q. Location, grading, design water levels, and planting details of all mitigation areas;

Mitigation for the 3.95 (or less) acres of permanent clearing/fill impacts in wetlands will be determined during post-submittal agency negotiations.

R. Site grading details, including perimeter site grading;

The new transmission line will include site fill for the keyhole pads and access road. The transmission line route will be brought up to original grade upon completion of installation. (See Engineering Drawings.)

S. Disposal site for any excavated material, including temporary and permanent disposal sites;

Excavated material will be disposed in compliance with local landfill regulations and OUC's current operating protocol.

T. Dewatering plan details;

If dewatering is required for construction then a short-term dewatering permit will be secured. If dewatering is required, it is anticipated that the dewatering system anticipated for this project will be a low-point well and ditch system to lower the ground water elevation sufficient below the bottom of excavation to preclude problems with backfilling, soil compaction, and other related activities. Ground water collected as a result of dewatering will be pumped to a contained upland area.

U. For marina facilities, locations of any sewage pumpout facilities, fueling facilities, boat repair and maintenance facilities, and fish cleaning stations;

Not Applicable.

V. Location and description of any nearby existing offsite features which might be affected by the proposed construction or development such as stormwater management ponds, buildings or other structures, wetlands or other surface waters.

No offsite features will be impacted by the proposed construction

W. For phased projects, provide a master development plan.

Project development will require only one phase. Therefore, a master development plan is not required.

IV. Construction Schedule and Techniques

Provide a construction schedule, and a description of construction techniques, sequencing and equipment. This information should specifically include the following:

A. Method for installing any pilings or seawall slabs;

B. Schedule of implementation of temporary or permanent erosion and turbidity control measures;

C. For projects that involve dredging or excavation in wetlands or other surface waters, describe the method of excavation, and the type of material to be excavated;

D. For projects that involve fill in wetlands or other surface waters, describe the source and type of fill material to be used. For shoreline stabilization projects that involve the installation of riprap, state how these materials are to be placed, (i.e., individually or with heavy equipment) and whether the rocks will be underlain with filter cloth;

E. If dewatering is required, detail the dewatering proposal including the methods that are proposed to contain the discharge, methods of isolating dewatering areas, and indicate the period dewatering structures will be in place (Note: a consumptive use or water use permit may by required);

F. Methods for transporting equipment and materials to and from the work site. If barges are required for access, provide the low water depths and draft of the fully loaded barge;

G. Demolition plan for any existing structures to be removed; and

H. Identify the schedule and party responsible for completing monitoring, record drawings, and as-built certifications for the project when completed.

Several distinct tasks will be required for construction of the proposed transmission line. These will include surveying, clearing, road construction, foundation construction, structure assembly and erection, conductor and shield wire installation, and cleanup. No demolition is required prior to constructing the new transmission line. The tasks will occur in the following sequence and will be separated, in time, by several days to several months.

The right-of-way centerline and edges and structure sites are established prior to construction. This task is usually performed by three to five person survey teams and requires minimum clearing for a line of sight. Erosion control measures will be implemented prior to any construction activities. Clearing and road construction usually run concurrently because of similar requirements for heavy equipment. Road construction is necessary where the structure site would otherwise be under water or the terrain will not support the heavy equipment to be used in subsequent phases of work.

In wetlands connected to waters of the state, chain saws and/or light, tracked shear machines will be used for clearing. Clean fill material will be hauled in for the construction of access roads. The source of the clean fill has not yet been determined. Stumps and root mat will be left in place, except at structure foundation locations. There will be no need to demuck.

In areas outside of wetlands, the right-of-way will be cleared by heavy-tracked machines, usually bulldozers, and dressed to facilitate future maintenance using wheeled tractors with bush-hog mowers. Stumps and cuttings will be piled and burned. The disposal method will depend on OUC preferences, requirements of the Division of Forestry, and other conditions at the time.

Fill material for access roads and key hole fills will be hauled in by truck and spread with bulldozers to obtain suitable compaction. Culverts, if required, will be installed as the road construction progresses to maintain drainage and water flow.

Construction of concrete foundations will occur during the second phase of construction. Equipment required for foundation construction consists of an augering machine mounted on tracked or all wheel drive vehicles, ready-mix concrete trucks, water trucks, pile driving equipment, and medium-sized (25 to 75 ton) track cranes. Each work group will have a bulldozer available to assist in the installation. Tractors, trailers, and light vehicles are used to transport material and personnel.

A short-term dewatering permit will be secured for construction activities associated with the electric transmission line, if dewatering is required. The dewatering system anticipated for this project will be a low-point well and ditch system to lower the ground water elevation sufficient below the bottom of

excavation to preclude problems with backfilling, soil compaction, and other related activities. Ground water collected as a result of dewatering will be pumped to a contained upland area.

The next series of tasks consists of hauling material, assembly of structures, erection of structures, and installation of the conductors. The structures and conductor hardware will probably be hauled to the site by tractors and trailers then offloaded with medium-sized truck cranes or all-wheeled cranes. Medium-sized (1.5 to 2 ton) all-wheel drive trucks will be used to transport personnel and tools. Medium-size trucks or all-wheel drive cranes are required to move structure components and place the structure for erection. The most common method of erecting the structure is with heavy tracked cranes. A work group will normally place the entire structure in one pick. The boom reach will be sufficient to work the tallest structures. Insulators and roller blocks are installed during or immediately following this task. The location of the work site for installation of conductors and shield wires is determined by the length of conductor on a reel or the line configuration. The basic equipment used for conductor installation is a matched set of machines (puller and tensioner) to pull the conductor and static wires through the rollers to the receiving end and, at the same time, to retard the conductor or maintain light tension at the sending end. The conductors and shield wires are hauled to the sending end on tractors and trailers. A variety of other equipment (radio-equipped pickups to medium-sized cranes and bulldozers) is required at both ends to complete the pull. The puller and tensioner then "leap-frog" as consecutive sections are completed. A bulldozer with a three or four drum winch is ordinarily used at the receiving ends to bring the conductors to final tension. The rollers are then removed and the conductors are permanently affixed to each structure. The time required to complete a pull averages less than 1 week.

Finally, at each heavy-angle or dead-end structure, it is necessary to install short pieces of conductor between the ends in order to electrically connect the conductors. Structures, fences, and gates are grounded during this phase of construction and before the line is energized.

Each contractor will be required to have sufficient equipment and personnel to maintain roads and to keep the right-of-way clear of debris and waste materials. In addition, culverts, if required, will be placed at necessary locations to allow for proper sheet flow and prevent road washouts. If necessary, restoration, including grading the soil and replanting or reseeding disturbed areas of the construction site, will be accomplished prior to the end of the construction phase of the project. The construction contractor will be required to provide stormwater monitoring, record drawings, and as-built certifications for the project when it is completed

V. Drainage Information

A. Provide pre-development and post-development drainage calculations, signed and sealed by an appropriate registered professional, as follows:

Not Applicable to the electric transmission line.

1. Runoff characteristics, including area, runoff curve number or runoff coefficient, and time of concentration for each drainage basin;

2. Water table elevations (normal and seasonal high) including aerial extent and magnitude of any proposed water table draw down;

3. Receiving water elevations (normal, wet season, design storm);

4. Design storms used including rainfall depth, duration, frequency, and distribution;

5. Runoff hydrograph(s) for each drainage basin, for all required design storm event(s);

6. Stage-storage computations for any area such as a reservoir, close basin, detention area, or channel, used in storage routing;

7. Stage-discharge computations for any storage areas at a selected control point, such as control structure or natural restriction;

8. Flood routings through on-site conveyance and storage areas;

9. Water surface profiles in the primary drainage system for each required design storm event(s);

10. Runoff peak rates and volumes discharged from the system for each required design storm event(s);

11. Tail water history and justification (time and elevation); and

12. Pump specifications and operating curves for range of possible operating conditions (if used in system).

B. Provide the results of any percolation tests, where appropriate, and soil borings that are representative of the actual site conditions;

Detailed subsurface conditions have been determined from the results of subsurface investigations completed for the existing Stanton Energy Center. These investigations include soil borings, installation of shallow piezometers, soil resistivity tests, and laboratory tests on selected samples. Data collected from these investigations is available (upon request) in the following four data reports:

- **ix. Soil Investigation, Orlando Utilities Commission – Stanton Energy Center, Black & Veatch project No. 8927, includes Phase I Soil Investigation.**
- **x. Laboratory Testing, Orlando Utilities Commission – Curtis H. Stanton Plant, Orlando, Florida, by Ardaman & Associates, Inc., September 10, 1980.**
- **xi. Laboratory Testing, Orlando Utilities Commission – Curtis H. Stanton Plant, Orlando, Florida, august 6, 1981, by Ardaman & Associates, Inc.**
- **xii. Laboratory and Field Materials Test Results, Orlando Utilities Commission – Stanton Energy Center Unit 2, Orlando, Florida, Black & Veatch Project No. 16805, by Universal Engineering Sciences, Inc., May 28, 1992.**

C. Provide the acreage, and percentages of the total project, of the following:

1. Impervious surfaces, excluding wetlands;
0 acres

2. Pervious surfaces (green areas, not including wetlands);
1.83 acres
Total =1.83/5.8 acres = 31.55 %

3. Lakes, canals, retention areas, other open water areas; and
Lakes, canals, retention areas: 0.02 acres (roadside ditch)
Total = 0.02/5.8 acres = 0.35 %

4. Wetlands.
Wetlands: 0.12 acres cypress strand; 3.83 acres hydric pine savanna = 3.95 acres
Total = 3.95/5.8 acres = 68.10 %

D. Provide an engineering analysis of floodplain storage and conveyance (if applicable), including:
Not Applicable

1. Hydraulic calculations for all proposed traversing works;

2. Backwater water surface profiles showing upstream impact of traversing works;

3. Location and volume of encroachment within regulated floodplain(s); and

4. Plan for compensating floodplain storage, if necessary, and calculations required for determining minimum building and road flood elevations.

E. Provide an analysis of the water quality treatment system including:

1. A description of the proposed stormwater treatment methodology that addresses the type of treatment, pollution abatement volumes, and recovery analysis; and

Stormwater treatment is not applicable to the electric transmission line. Stormwater associated with these facilities will continue to drain to existing drainage patterns.

2. Construction plans and calculations that address stage-storage and design elevations, which demonstrate compliance with the appropriate water quality treatment criteria.

Not applicable to the electric transmission line.

F. Provide a description of the engineering methodology, assumptions and references for the parameters listed above, and a copy of all such computations, engineering plans, and specifications used to analyze the system. If a computer program is used for the analysis, provide the name of the program, a description of the program, input and output data, two diskette copies, if available, and justification for model selection.

If a culvert is required, the associated engineering calculations will be provide prior to construction.

VI. Operation and Maintenance and Legal Documentation

A. Describe the overall maintenance and operation schedule for the proposed system.

No stormwater facilities are associated with the electric transmission line. The OUC will conduct regular inspections of the transmission line facilities.

B. Identify the entity that will be responsible for operating and maintaining the system in perpetuity if different than the permittee, a draft document enumerating the enforceable affirmative obligations on the entity to properly operate and maintain the system for its expected life, and documentation of the entity's financial responsibility for long-term maintenance. If the proposed operation and maintenance entity is not a property owner's association, provide proof of the existence of an entity, or the future acceptance of the system by an entity which will operate and maintain the system. If a property owner's association is the proposed operation and maintenance entity, provide copies of the articles of incorporation for the association and copies of the declaration, restrictive covenants, deed restrictions, or other operational documents that assign responsibility for the operation and maintenance of the system. Provide information ensuring the continued adequate access to the system for maintenance purposes. Before transfer of the system to the operating entity will be approved, the permittee must document that the transferee will be bound by all terms and conditions of the permit.

Not applicable.

C. Provide copies of all proposed conservation easements, stormwater management system easements, property owner's association documents, and plats for the property containing the proposed system.

Orlando Utilities Commission owns all of the project area. Thus, no easements apply.

D. Provide indication of how water and waste water service will be supplied. Letters of commitment from off-site suppliers must be included.

Not applicable.

E. Provide a copy of the boundary survey and/or legal description and acreage of the total land area of contiguous property owned/controlled by the applicant.

Please refer to Figure A1 of this ERP for property boundaries of the Curtis H. Stanton Energy Center. Construction of the electric transmission line will occur entirely within the property boundary described in the above-mentioned figures. Orlando Utilities Commission owns this property. Ownership documents can be provided upon request.

VII. Water Use

A. Will the surface water system be used for water supply, including landscape irrigation, or recreation.

Not applicable.

B. If a Consumptive Use or Water Use permit has been issued for the project, state the permit number.

Not applicable.

C. If no Consumptive Use or Water Use permit has been issued for the project, indicate if such a permit will be required and when the application for a permit will be submitted.

No Consumptive Use or water Use permit will be required for this project.

D. Indicate how any existing wells located within the project site will be utilized or abandoned.

Not applicable

TABLE 1
Project Impact Summary

WL & SW ID	WL & SW TYPE	WL & SW SIZE (ac.) ON SITE	WL & SW ACRES NOT IMPACTED	PERMANENT IMPACTS TO WL & SW		TEMPORARY IMPACTS TO WL & SW		MITIGATION ID
				IMPACT SIZE (acres)	IMPACT CODE	IMPACT SIZE (acres)	IMPACT CODE	
1	**Cypress Strand**	**0.12**	**0**	**0.06/0.06**	**C/F**	**NA**	**NA**	**To be determined**
2	**Hydric Pine Savanna**	**3.83**	**0**	**2.40/1.43**	**C/F**	**NA**	**NA**	**To be determined**
3	**Roadside Ditch**	**0.02**	**0.02**	**NA**	**NA**	**NA**	**NA**	**Not required**

WL = Wetland; **SW** = Surface water; **ID** = Identification number, letter, etc.
Wetland Type: Use an established wetland classification system and, in the comments section below, indicate which classification system is being used.
Impact Code (Type): D = dredge; F = fill; H = change hydrology; S = shading; C = clearing; O = other. Indicate the final impact if more than one impact type is proposed in a given area. For example, show F only for an area that will first be demucked and then backfilled.

Note: Multiple entries per cell are not allowed, except in the "Mitigation ID" column. Any given acreage of wetland should be listed in one row only, such that the total of all rows equals the project total for a given category (column). For example, if Wetland No. 1 includes multiple wetland types and multiple impact codes are proposed in each type, then each proposed impact in each wetland type should be shown on a separate row, while the size of each wetland type found in Wetland No. 1 should be listed in only one row.

TABLE 2
ON-SITE MITIGATION SUMMARY

MITIGATION ID	CREATION		RESTORATION		ENHANCEMENT		WETLAND PRESERVE		UPLAND PRESERVE		OTHER	
	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TARGET TYPE
					SEE COMMENT BELOW							
PROJECT TOTALS:												

CODES (multiple entries per cell not allowed): Target Type or Type = target or existing habitat type from an established wetland classification system or land use classification for non-wetland mitigation

COMMENTS: Mitigation for the 3.95 acres (or less) of permanent impact will be determined during post-submitted agency negotiations.

TABLE 3
OFF-SITE MITIGATION SUMMARY

MITIGATION ID	CREATION		RESTORATION		ENHANCEMENT		WETLAND PRESERVE		UPLAND PRESERVE		OTHER	
	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TARGET TYPE	AREA	TARGET TYPE
					SEE COMMENT BELOW							
PROJECT TOTALS:												

CODES (multiple entries per cell not allowed):
Target Type=target or existing habitat type from an established wetland classification system or land use classification for non-wetland mitigation

Comments: Mitigation for the 3.95 acres (or less) of permanent impact will be determined during post-submitted agency negotiations.

TABLE 4
DOCKING FACILITY SUMMARY

Type of Structure*	Type of Work**	Number of Identical Docks	Length (feet)	Width (feet)	Height (feet)	Total square feet over water	Number of slips
		NOT APPLICABLE					

TOTALS:	Existing	Proposed
Number of Slips		
Square Feet over the water		

*Dock, Pier, Finger Pier, or other structure (please specify what type)

**New, Replaced, Existing (unaltered), Removed, or Altered/Modified

Use of Structure:

Will the docking facility provide:

Live-aboard Slips? If yes, Number:
Fueling Facilities: If yes, Number
Sewage Pump-out Facilities? If yes, Number:
Other Supplies or Services Required for Boating (excluding refreshments, bait and tackle)
☐ Yes ☐No

Type of Materials for Decking and Pilings (i.e., CCA, pressure treated wood, plastic, or concrete)

Pilings
Decking
Proposed Dock-Plank Spacing (if applicable)

Proposed Size (length and draft), Type, and Number of Boats Expected to Use or Proposed to be Mooring at the facility)

Table 5: SHORELINE STABILIZATION
IF YOU ARE CONSTRUCTING A SHORELINE STABILIZATION PROJECT, PLEASE PROVIDE THE FOLLOWING:

Type of Stabilization Being Done	Length (in feet) of New	Length (in feet) of Replaced	Length (in feet) of Repaired	Length (in feet) of Removed	Slope: H: V:	Width of the Toe (in feet)
Vertical Seawall		**NOT APPLICABLE**				
Seawall plus Rip-Rap						
Rip-Rap						
Rip-Rap plus Vegetation						
Other Type of Stabilization Being Done:						

Size of the Rip Rap: _____

Type of Rip Rap:_____

COMMENTS:

SECTION F

Information for Mitigation Banks

NOT APPLICABLE

Please provide the information requested below if you are applying for a mitigation bank permit or a mitigation bank conceptual approval.

A. General Site Conditions. Provide the following:

1. A map, at regional scale, of the mitigation bank in relation to the regional watershed and proposed mitigation service area.

2. A vicinity map showing the mitigation bank in relation to adjacent lands and off-site areas of ecological or hydrologic significance which could affect the long term viability or ecological value of the bank;

3. A recent aerial photo of the mitigation bank (no photocopies) identifying boundaries of the project area;

4. A highway map showing points of access to the mitigation bank for site inspection;

5. A legal description of the proposed mitigation bank;

6. A description and assessment of current site conditions including:

(a) a soils map of the mitigation bank site;
(b) a topographic map of the mitigation bank site and adjacent hydrologic contributing and receiving areas;
(c) a hydrologic features map of the mitigation bank and adjacent hydrologic contributing and receiving areas;
(d) current hydrologic conditions in the mitigation bank site;
(e) a vegetation map of the mitigation bank site;
(f) ecological benefits currently provided to the regional watershed by the mitigation bank site;
(g) adjacent lands, including existing land uses and conditions, projected land uses according to comprehensive plans adopted pursuant to Chapter 163, F.S., by local governments having jurisdiction, and any special designations or classifications associated with adjacent lands or waters;
(h) a disclosure statement of any material fact which may affect the contemplated use of the property; and
(i) a Phase I environmental audit of the property (not required for a Conceptual Approval).

B. Mitigation Bank Information

1. A description of the ecological significance of the proposed mitigation bank to the regional watershed in which it is located.

2. A mitigation plan describing the actions proposed to establish, construct, operate, manage and maintain the mitigation bank including:

(a) construction-level drawings detailing proposed topographic alterations and all structural components associated with proposed activities (not required for a Conceptual Approval);
(b) proposed construction activities, including a detailed schedule for implementation (not required for a Conceptual Approval);
(c) the proposed vegetation planting scheme and detailed schedule for implementation;
(d) measures to be implemented during and after construction to avoid adverse impacts related to proposed activities;
(e) a detailed long-term management plan comprising all aspects of operation and maintenance, including water management practices, vegetation establishment, exotic and nuisance species control, fire management, and control of access; and
(f) a proposed monitoring plan to demonstrate mitigation success.

3. An assessment of improvement or changes in ecological value anticipated as a result of proposed mitigation actions including:

(a) a description of anticipated site conditions in the mitigation bank after the mitigation plan is successfully implemented;

(b) a comparison of current fish and wildlife habitat to expected habitat after the mitigation plan is successfully implemented; and

(c) a description of the expected ecological benefits to the regional watershed.

4. Evidence of sufficient legal or equitable interest in the property which is to become the mitigation bank to meet the requirements of the Applicant's Handbook / Basis of Review (not required for a Conceptual Approval).

5. Draft documentation of financial responsibility meeting the requirements of the Applicant's Handbook / Basis of Review (not required for a Conceptual Approval).

6. Any engineering calculations and/or computer modeling (such as hydrograph or staging) needed to assess the effects of the project on the hydrologic characteristics of the mitigation bank site and upstream and downstream areas.

SECTION G

Application for Authorization to Use Sovereign Submerged Lands

Part 1: Sovereign Submerged Lands title information (see Attachment 5 for an explanation). Please read and answer the applicable questions listed below:

A. I have a sovereign submerged lands title determination from the Division of State Lands which indicates that the proposed project is NOT ON sovereign submerged lands (Please attach a copy of the title determination to the application). Yes☐ No☒

- If you answered Yes to Question A and you have attached a copy of the Division of State Lands Title Determination to this application, you do not have to answer any other questions under Part I or II of Section G.

B. I have a sovereign submerged lands title determination from the Division of State Lands which indicates that the proposed project is ON sovereign submerged lands (Please attach a copy of the title determination to the application). Yes☐ No☒

- If you answered yes to question B please provide the information requested in Part II. Your application will be deemed incomplete until the requested information is submitted.

C. I am not sure if the proposed project is on sovereign submerged lands (please check here). ☐

- If you have checked this box department staff will request that the Division of State Lands conduct a title determination. If the title determination indicates that the proposed project or portions of the project are located on sovereign submerged lands you will be required to submit the information requested in Part II of this application. The application will be deemed incomplete until the requested information is submitted.

D. I am not sure if the proposed project is on sovereign submerged lands and I DO NOT WISH to contest the Department's findings (please check here). ☐

- If you have checked this box refer to Part II of this application and provide the requested information. The application will be deemed incomplete until the requested information is submitted.

E. It is my position that the proposed project is NOT on sovereign submerged lands (please check here) ☒

- If you have evidence that indicates that the proposed project is not on sovereign submerged lands please attach the documentation to the application. If the Division of State Lands title determination indicates that your proposed project or portion of your proposed project are on sovereign submerged lands you will be required to provide the information requested in Part II of this application.

F. If you wish to contest the findings of the title determination conducted by the Division of State Lands please contact the Department of Environmental Protection's Office of General Counsel. Your proposed project will be deemed incomplete until either the information requested in Part II is submitted or a legal ruling indicates that the proposed project is not on sovereign submerged lands.

<u>Part II</u>: If you were referred to this section by Part I, please provide this additional information. Please note that if your proposed project is on sovereign submerged lands and the below requested information is not provided, your application will be considered incomplete.

A. Provide evidence of title to the subject riparian upland property in the form of a recorded deed, title insurance, legal opinion of title, or a long-term lease which specifically includes riparian rights. Evidence submitted must demonstrate that the application has sufficient title interest in the riparian upland property.

B. Provide a detailed statement describing the existing and proposed upland uses and activities. For commercial uses, indicate the specific type of activity, such as marina, ship repair, dry storage (including the number of storage spaces), commercial fishing/seafood processing, fish camp, hotel, motel resort restaurant, office complex, manufacturing operation, etc.

For rental operations, such as trailer or recreational vehicle parks and apartment complexes, indicate the number of wet slip units/spaces available for rent or lease and describe operational details (e.g., are spaces rented on a month-to-month basis or through annual leases).

For multi-family residential developments, such as condominiums, townhomes, or subdivisions, provide the number of living units/lots and indicate whether or not the common property (including the riparian upland property) is or will be under the control of a homeowners association.

For projects sponsored by a local government, indicate whether or not the facilities will be open to the general public. Provide a breakdown of any fees that will be assessed, and indicate whether or not such fees will generate revenue or will simply cover costs associates with maintaining the facilities.

C. Provide a detailed statement describing the existing and proposed activities located on or over the sovereign submerged lands at the project site. This statement must include a description of docks and piers, types of vessels (e.g., commercial fishing, liveaboards, cruise ships, tour boats), length and draft of vessels, sewage pumped facilities, fueling facilities, boat hoists, boat ramps, travel lifts, railways, and any other structure or activities existing or proposed to be located waterward of the mean/ordinary high water line.

If slips are existing and/or proposed, please indicate the number of powerboat slips and sailboat slips and the percentage of those slips available to the general public on a "first come, first served" basis. This statement must include a description of channels, borrow sites, bridges, groins, jetties, pipelines, or other utility crossings, and any other structures or activities existing or proposed to be located waterward of the mean/ordinary high water line. For shoreline stabilization activities, this statement must include a description of seawalls, bulkheads, riprap, filling activities, and any other structure or activities existing or proposed to be located along the shoreline.

D. Provide the linear footage of shoreline at the mean/ordinary high water line owned by the application which borders sovereign submerged lands.

E. Provide a recent aerial photo of the area. A scale of 1"=200' is preferred. Photos are generally available at minimal cost from your local government property appraiser's office or from district Department of Transportation offices. Indicate on the photo the specific location of your property/project site.

PROPRIETARY PROJECT DESCRIPTIONS

Please check the most applicable activity which applies to your project(s):

Leases

☐ Commercial marinas (renting wet slips) including condos, etc., if 50% or more of their wet slips are available to the general public
☐ Public/Local governments
☐ Yacht Clubs/Country Clubs (when a membership is required)
☐ Condominiums (requires upland ownership)
☐ Commercial Uplands Activity (temporary docking and/or fishing pier associated with upland revenue generating activities, i.e., restaurants, hotels, motels) for use of the customer at not charge
☐ Miscellaneous Commercial Upland Enterprises where there is a charge associated with the use of overwater structure (Charter Boats, Tour Boats, Fishing Piers)
☐ Ship Building/Boat Repair Service Facilities
☐ Commercial Fishing Related (Offloading, Seafood Processing)
☐ Private Single-family Residential Docking Facilities; Townhome Docking Facilities; Subdivision Docking Facilities (upland lots privately owned)

Public Easements and Use Agreements

☐ Miscellaneous Public Easements and Use Agreements
☐ Bridge Right-of-way (DOT, local government)
☐ Breakwater of groin
☐ Subaqueous Utility Cable (TV, telephone, electrical)
☐ Subaqueous Outfall or Intake
☐ Subaqueous Utility Water/Sewer
☐ Overhead Utility w/Support Structure on Sovereign Submerged Lands
☐ Disposal Site for Dredged Material
☐ Pipeline (gas)
☐ Borrow Site

Private Easements

☐ Miscellaneous Private Easements
☐ Bridge Right-of-way
☐ Breakwater Groin
☐ Subaqueous Utility Cable (TV, telephone, electrical)
☐ Subaqueous Outfall or Intake
☐ Subaqueous Utility Water/Sewer
☐ Overhead Utility Crossing
☐ Disposal Site for Dredged Material
☐ Pipeline (gas)

Consents of Use

- ☐ Aerial Utility Crossing w/no support structures on sovereign submerged lands
- ☐ Private Dock
- ☐ Public Dock
- ☐ Multi-family Dock
- ☐ Fishing Pier (private or Multi-family)
- ☐ Private Boat Ramp
- ☐ Sea Wall
- ☐ Dredge
- ☐ Maintenance Dredge
- ☐ Navigation Aids/Markers
- ☐ Artificial Reef
- ☐ Riprap
- ☐ Public Boat Ramp
- ☐ Public Fishing Pier
- ☐ Repair/Replace Existing Public Fishing Pier
- ☐ Repair/Replace Existing Private Dock
- ☐ Repair/Replace Existing Public Dock
- ☐ Repair/Replace Existing Multi-family Dock
- ☐ Repair/Replace Existing Fishing Pier (Private or Multi-family)
- ☐ Repair/Replace Existing Private Boat Ramp
- ☐ Repair/Replace Existing Sea Wall, Revetments, or Bulkheads
- ☐ Repair/Replace/Modify structures/activities within an exiting lease, easement, management agreement or use agreement area or repair/replace existing grandfathered structures
- ☐ Repair/Replace Existing Public Boat Ramp

Miscellaneous

- ☐ Biscayne Bay Letters of Consistency/Inconsistency w/258.397, F.S.
- ☐ Management Agreements - Submerged Lands
- ☐ Reclamation
- ☐ Purchase of Filled, Formerly Submerged Lands
- ☐ Purchase of Reclaimed Lake Bottom
- ☐ Treasure Salvage
- ☐ Insect Control Structures/Swales
- ☐ Miscellaneous projects which do not fall within the activity codes listed above

TABLES

Table E1. Wildlife Species Observed in Transmission Corridor Vicinity—November 2005

Common Name	Scientific Name
Reptiles	
Gopher tortoise	*Gopherus polyphemus*
Birds	
Great blue heron	*Ardea herodias*
Great egret	*Casmerodius albus*
Snowy egret	*Egretta thula*
Turkey vulture	*Cathartes aura*
Red-tailed hawk	*Buteo jamaicensis*
Florida sandhill crane	*Grus canadensis pratensis*
Killdeer	*Charadrius vociferous*
Belted kingfisher	*Ceryle alcyon*
Hairy woodpecker	*Picoides villosus*
Marsh wren	*Cistothorus palustris*
Catbird	*Dumetella carolinensis*
Northern mockingbird	*Mimus polyglottos*
Yellow-rumped warbler	*Dendroica coronata*
Palm warbler	*Dendroica palmarum*
Pine warbler	*Dendroica pinus*
Eastern meadowlark	*Sturnella magna*
Towhee	*Pipilo erythrophthalmus*
Cardinal	*Cardinalis cardinalis*
Mammals	
White-tailed deer	*Odocoileus virginianus*

Source: Supplemental Site Certification Application, February 2006

Table E2. State- or Federally Listed Wildlife Species Potentially Occurring on the Stanton Site and Likelihood of Occurrence within the Transmission Corridor

Common Name *Scientific Name*	Status* USFWS	 FWC	Likelihood of Occurrence Within Unit B Transmission Corridor
Amphibians			
Gopher frog *Rana capito*	—	SSC	Low—suitable habitat and gopher tortoise densities minimal
Reptiles			
American alligator *Alligator mississippiensis*	T(S/A)	SSC	Low—open water habitats minimal on the corridor
Eastern indigo snake *Drymarchon corais couperi*	T	T	Low—suitable habitat and gopher tortoise densities minimal
Gopher tortoise *Gopherus polyphemus*	—	SSC	Low—on the corridor, although one active and one inactive burrow observed along access road to existing Unit A transmission line
Florida pine snake *Pituophis melanoleucus migitus*	—	SSC	Low—habitat minimal
Short-tailed snake *Stilosoma extenuatum*	—	T	Low—habitat minimal
Birds			
Florida scrub jay *Aphelocoma c. coerulescens*	T	T	Low—habitat absent
Limpkin *Aramus guarauna*	—	SSC	Low—habitat absent
Florida burrowing owl *Athene cunicularia*	—	SSC	Low—habitat minimal
Little blue heron *Egretta caerulea*	—	SSC	Moderate—could forage in corridor wetlands
Snowy agret *Egretta thula*	—	SSC	Present—observed foraging in corridor
Tricolored heron *Egretta tricolor*	—	SSC	Moderate—could forage in corridor wetlands
White ibis *Eudocumus albus*	—	SSC	Moderate—could forage in corridor wetlands
Peregrine falcon *Falco peregrinus*	—	E	Low—possible migrant over the site; may forage along Orange County landfill or onsite ponds
Southeastern American kestrel *Falco sparverius paulus*	—	T	Moderate—may be expected on the pine flatwoods/open areas of the Stanton property
Florida sandhill crane *Grus canadensis pratensis*	—	T	Present—commonly observed on the grassed areas near the power block
Bale eagle *Haliaeetus leucocephalus*	T	T	Present—over the power block area and landfill; no known nesting within 0.5 mile of corridor
Wood stork *Mycteria americana*	E	E	Moderate—could forage in wetlands along the corridor; no known nests within 1 mile
Red-cockaded woodpecker *Picoides borealis*	E	SSC	Moderate—birds could forage in flatwoods and cypress wetlands along corridor; present on Stanton property, but nearest known colony is nearly 5,000 ft away
Kirtland's warbler *Dendroica kirtlandii*	—	E	Low—only occurs as a migrant, usually along coastal areas of Florida
Mammals			
Florida mouse *Podomys floridanus*	—	SSC	Low—habitat minimal and low density of gopher tortoises
Sherman's fox squirrel *Sciurus niger shermani*	—	SSC	Low—habitat absent
Florida black bear *Ursus americanus floridanus*	—	T	Low—habitat absent

* E = endangered. T(S/A) = threatened due to similarity of appearance.
T = threatened. SSC = species of special concern.

Source: Supplemental Site Certification Application, February 2006.

Table E3. Threatened/Endangered/Protected Plant Species Documented On or Near the Transmission Corridor

Common Name	Scientific Name	Status USFWS	Status FWC	Status FDACS
Greenfly orchid	*Epidendrum conopseum*			C
Catesby's lily (pine lily)	*Lilium catesbei*			T
Cinnamon fern	*Osmunda cinnamomea*			C
Royal fern	*Osmunda regalis*			C
Yellow-flowered butterwort	*Pinguicula lutea*			T
Rose pogonia	*Pogonia ophioglossoides*			T
Hooded pitcher plant	*Sarracenia minor*			T
Common wild pine	*Tillandsia fasiculata*			E
Giant wild pine	*Tillandsia utriculata*			E

Note: USFWS = U.S. Fish and Wildlife Service.
FWC = Florida Fish and Wildlife Conservation Commission.
FDACS = Florida Department of Agriculture and Consumer Services.
C = commercially exploited.
E = endangered.
T = threatened.

Source: Supplemental site Certification Application, February 2006

FIGURES

M:/ACAD/05[illegible]/ERP/Adjacent Lands to Stanton.mxd

FIGURE A1.
PROPERTIES ABUTTING AND ADJACENT TO THE STANTON ENERGY CENTER

Sources: SJRWMD Aerials, 2004; SSCA, 2006.

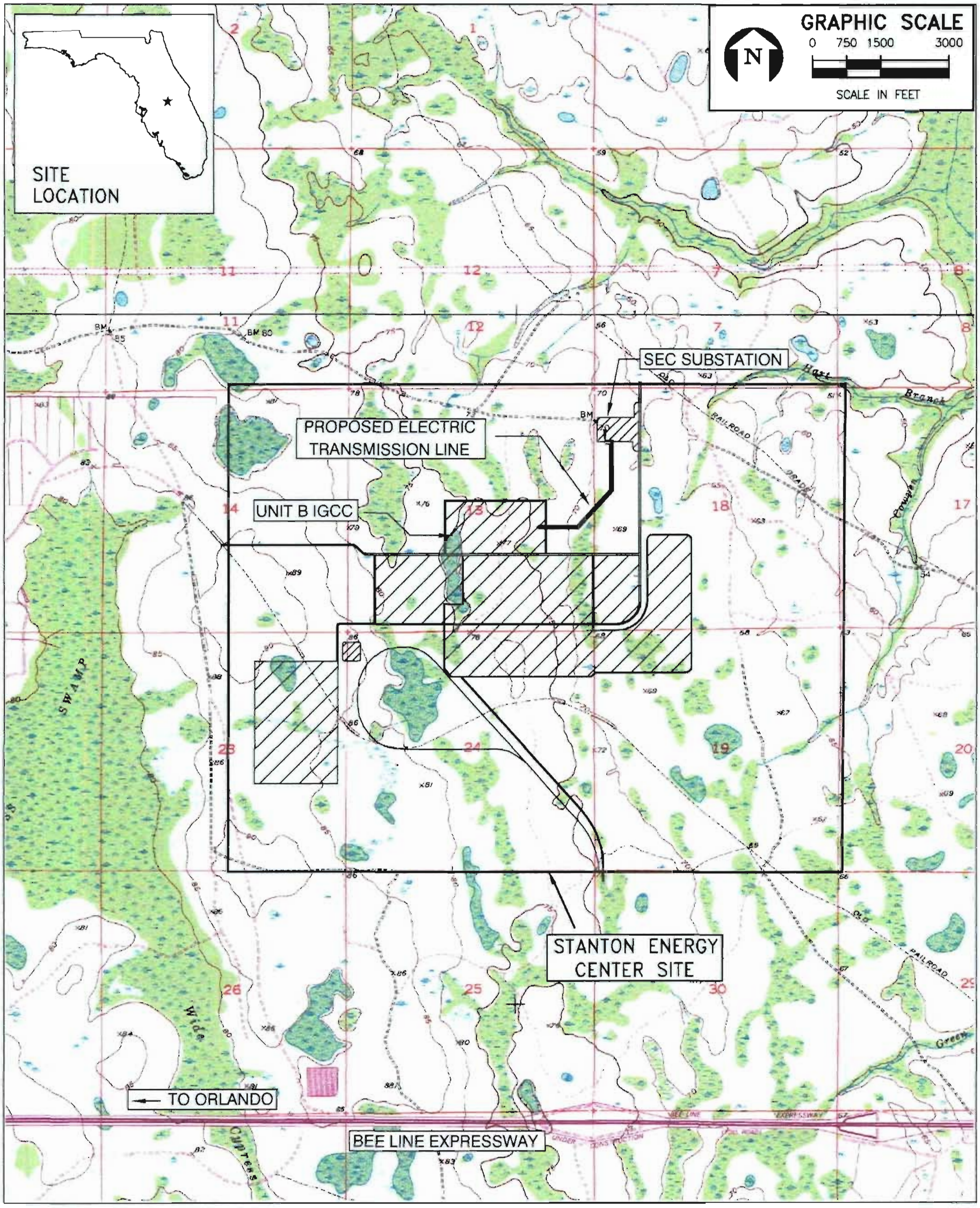


FIGURE C1.

STANTON SITE TOPOGRAPHY

Sources: USGS Quads: Oviedo SW and Narcoossee NW, FL, 1980; SSCA, 2006.

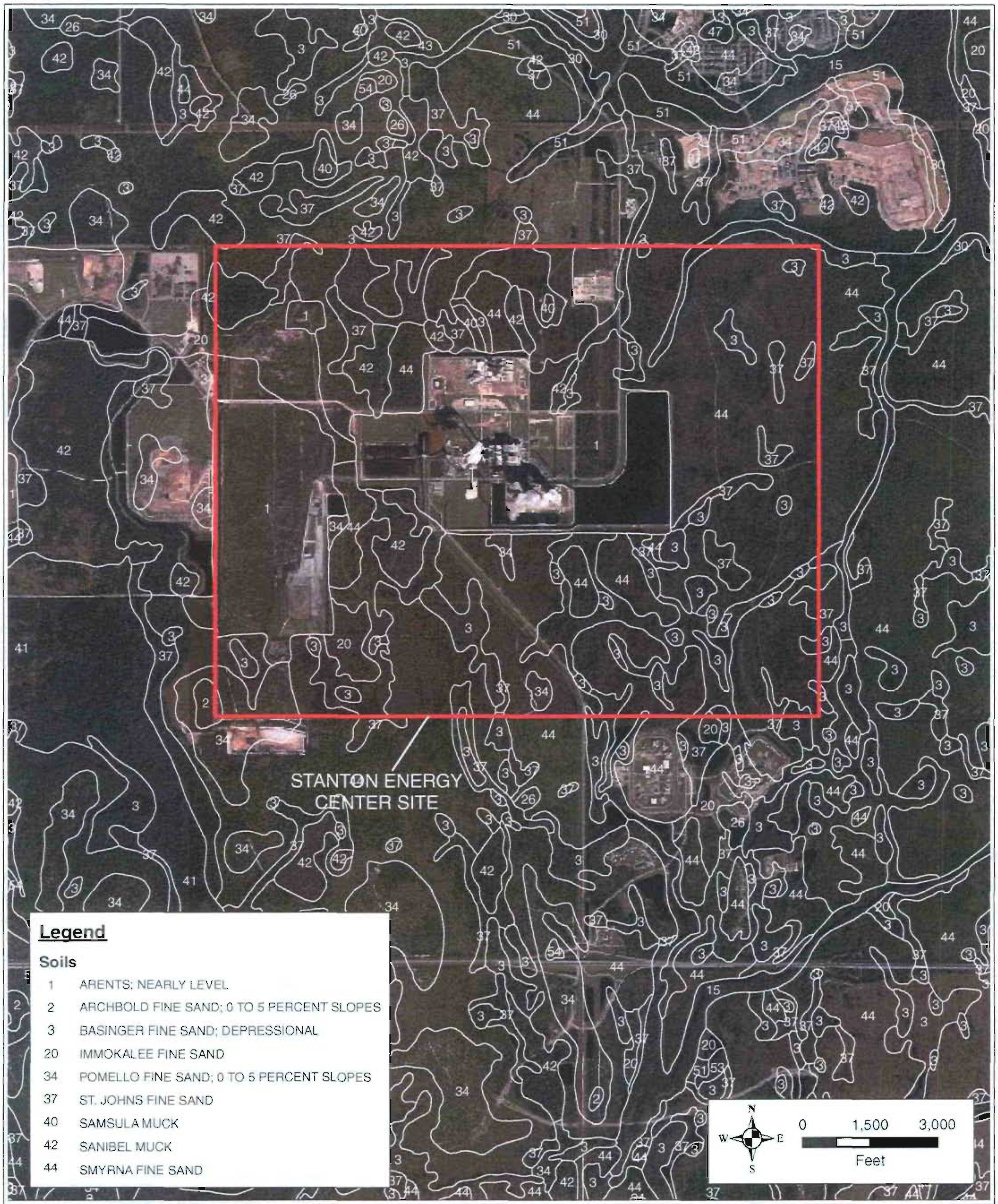


FIGURE E1.
SOILS MAP OF STANTON SITE

Sources: SJRWMD Aerial, 2004; SJRWMD Soils, 2005; SSCA, 2006.

M:/ACAD/05[illegible]/ERP/air_area.mxd

FIGURE E2.
2004 AERIAL OF STANTON SITE AND SURROUNDING AREA

Sources: SJRWMD Aerials, 2004; SSCA, 2006.

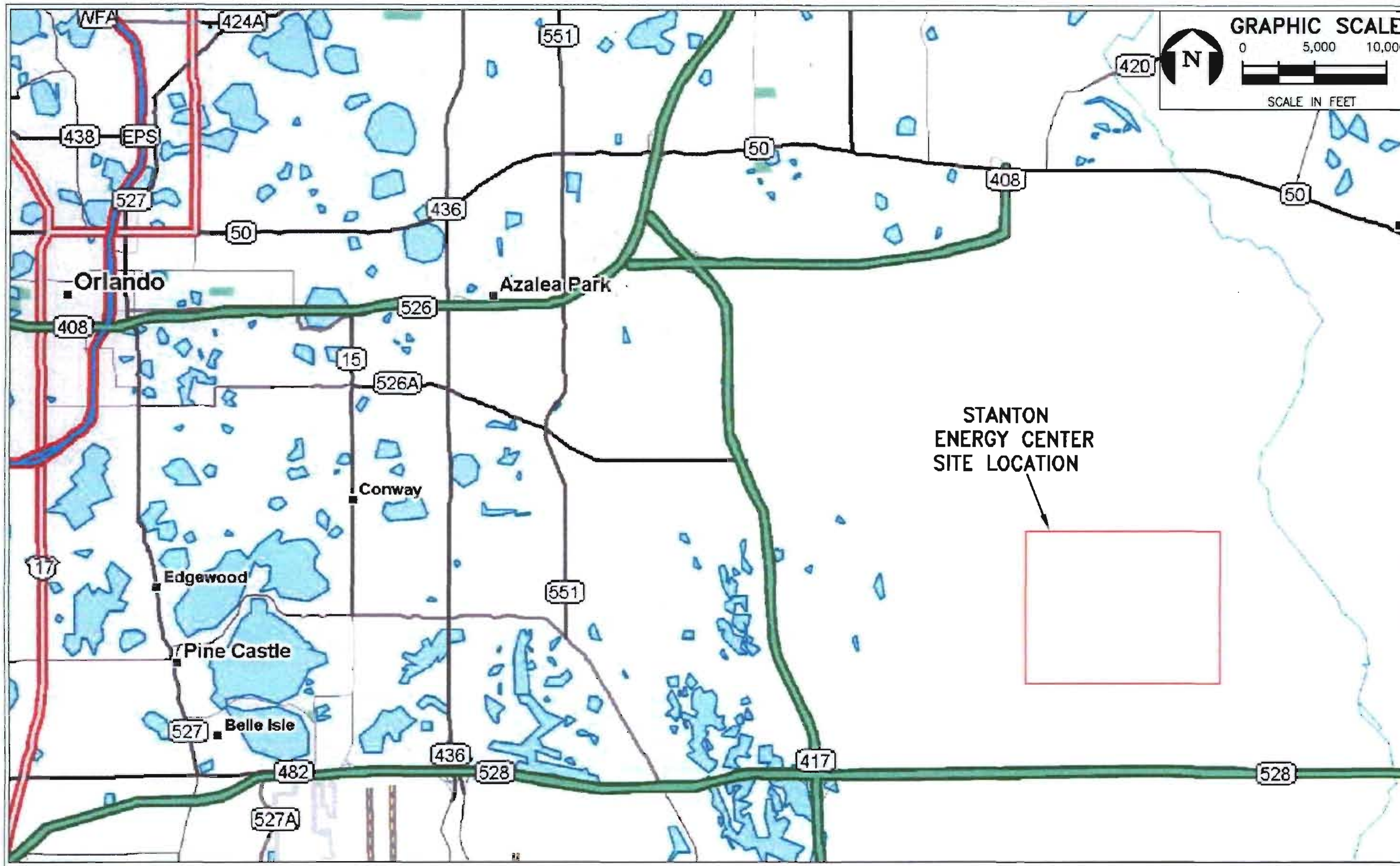
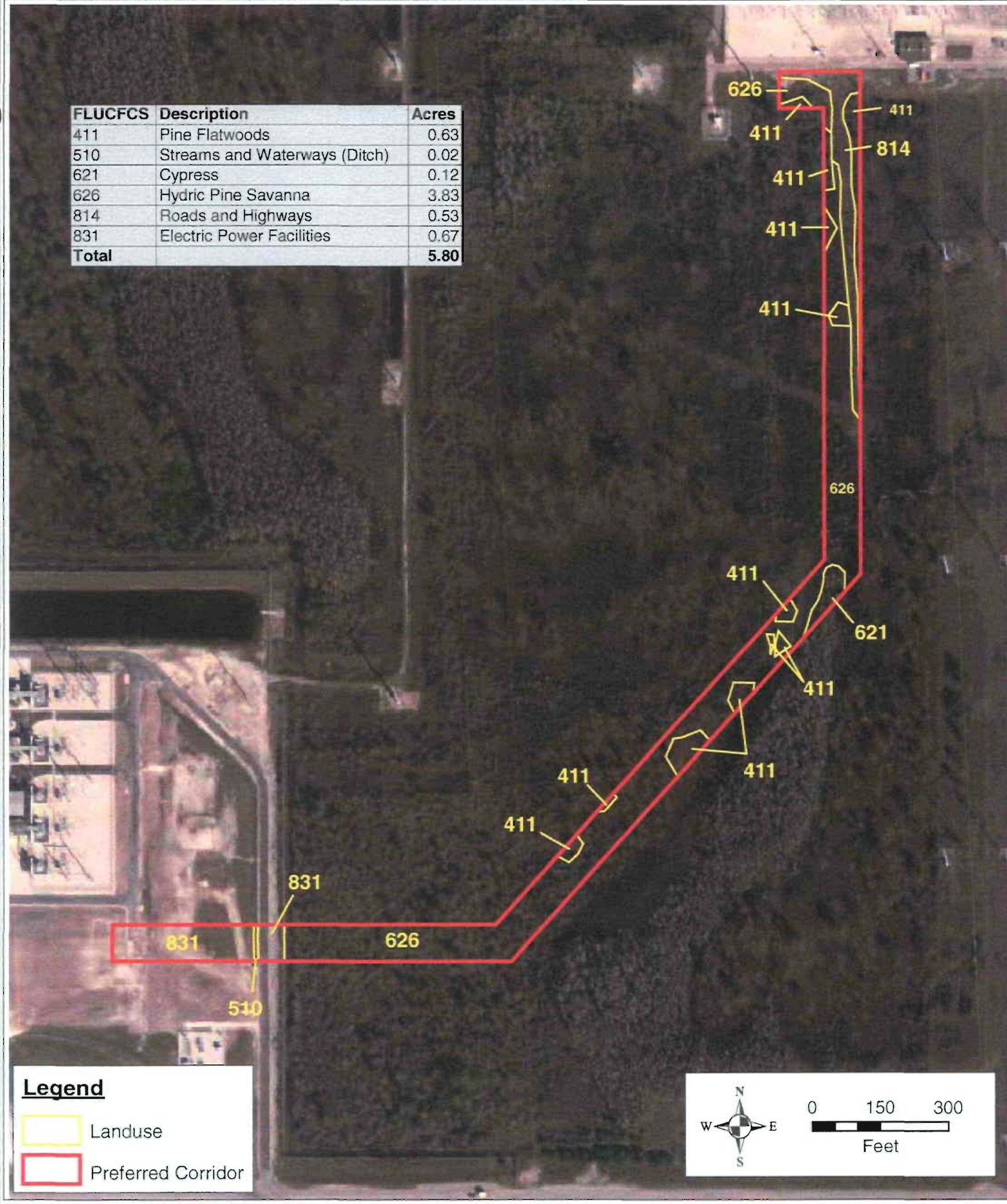


FIGURE E3.

STANTON SITE LOCATION RELATIVE TO ORLANDO

Source: DeLorme, 2003; SSCA, 2006.

M:/ACAD/051131/ERP/Land cover Vegetation.mxd



FLUCFCS	Description	Acres
411	Pine Flatwoods	0.63
510	Streams and Waterways (Ditch)	0.02
621	Cypress	0.12
626	Hydric Pine Savanna	3.83
814	Roads and Highways	0.53
831	Electric Power Facilities	0.67
Total		**5.80**

FIGURE E4.
LAND COVER/VEGETATION ALONG THE PROPOSED CORRIDOR

Sources: SJRWMD, 2005; SSCA, 2006.

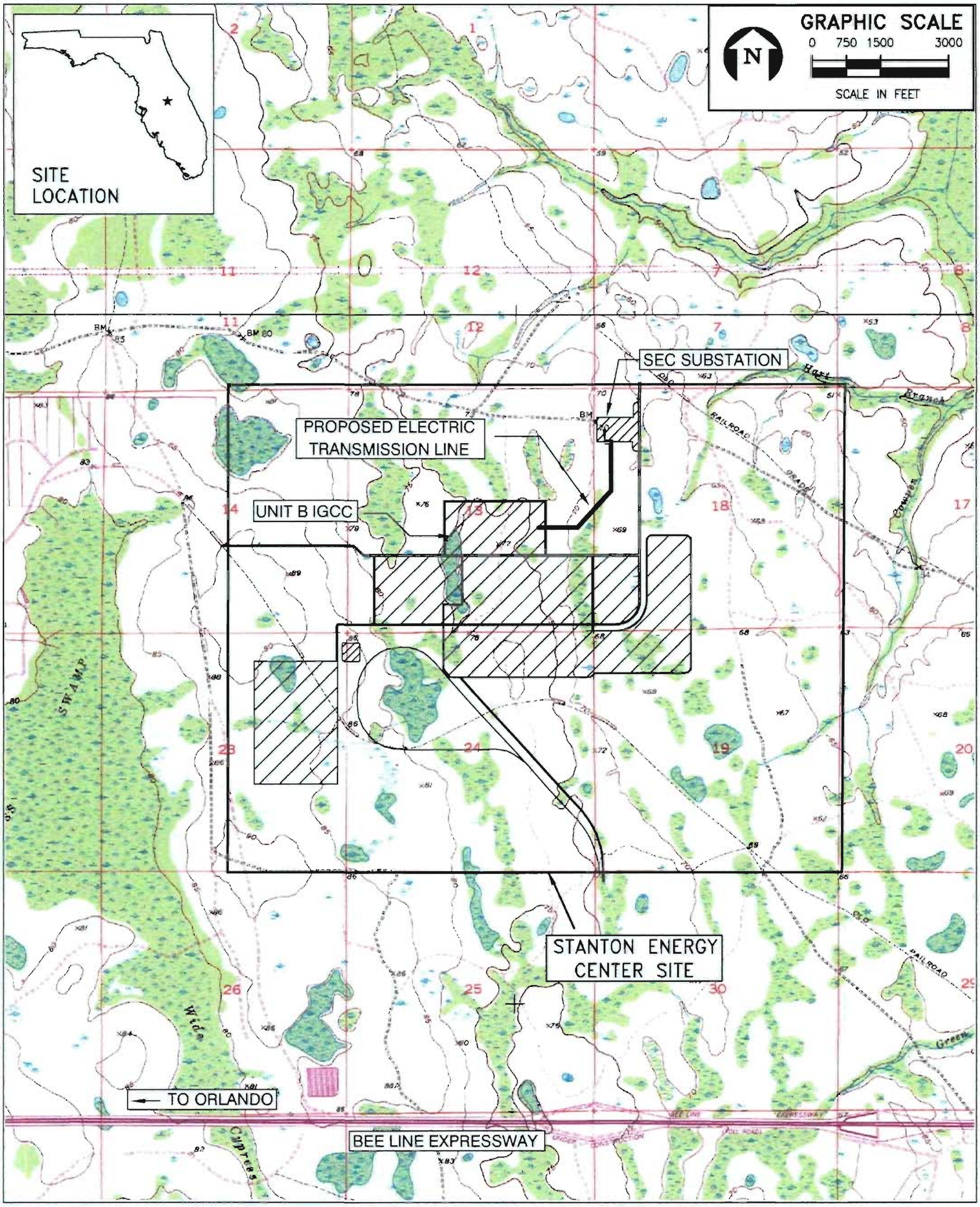


FIGURE E5.

STANTON SITE TOPOGRAPHY

Sources: USGS Quads: Oviedo SW and Narcoossee NW, FL, 1980; SSCA, 2006.

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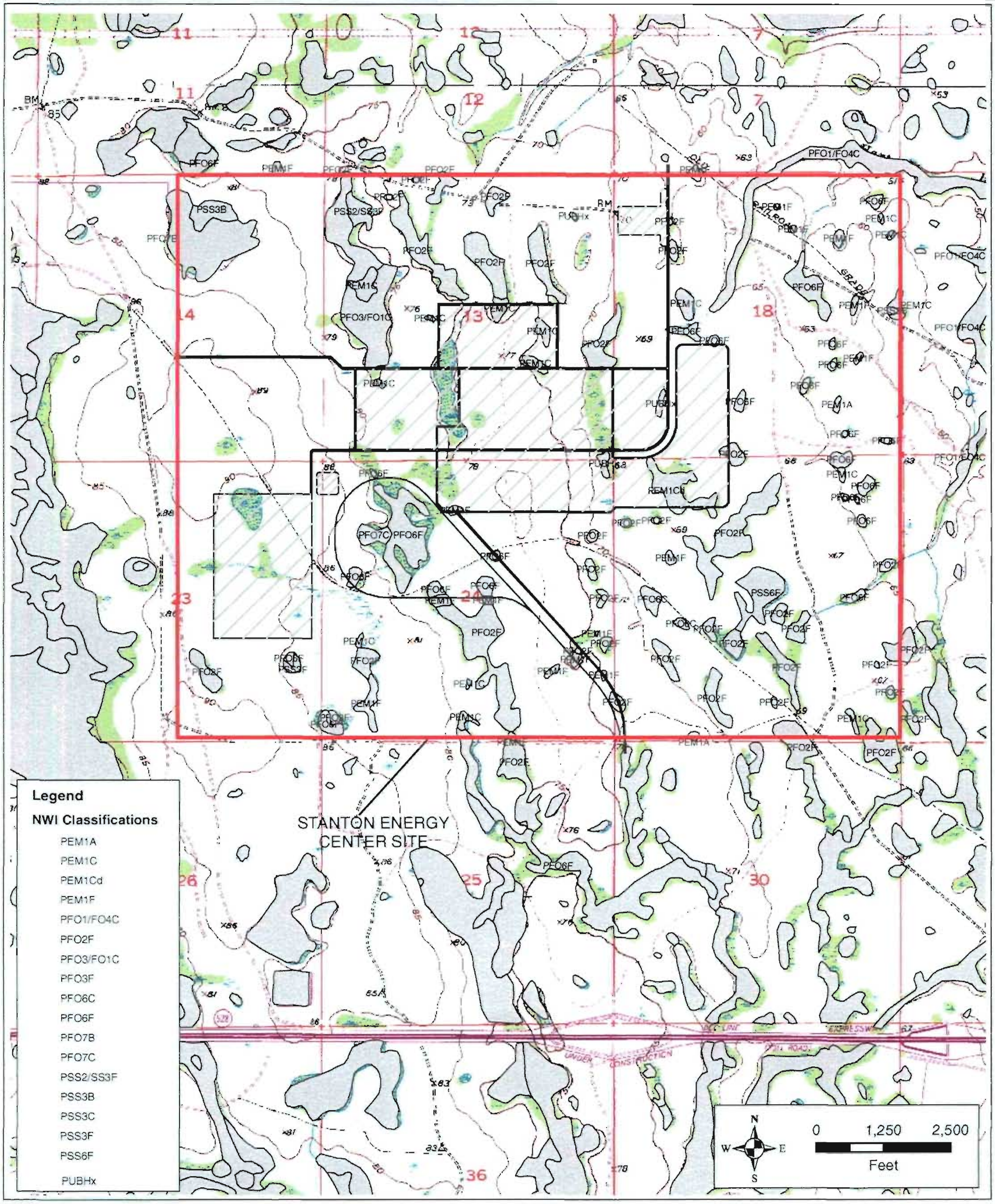
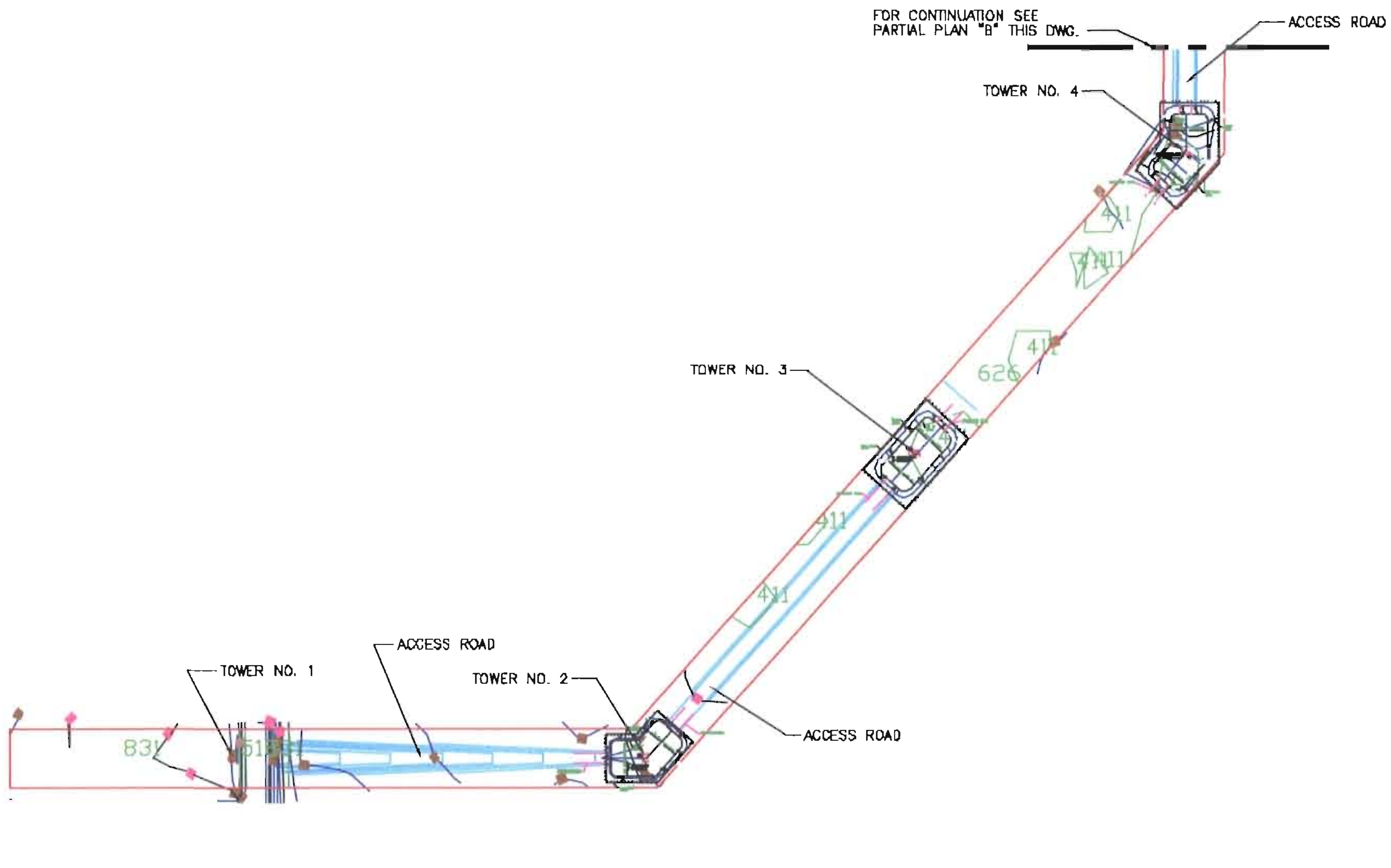


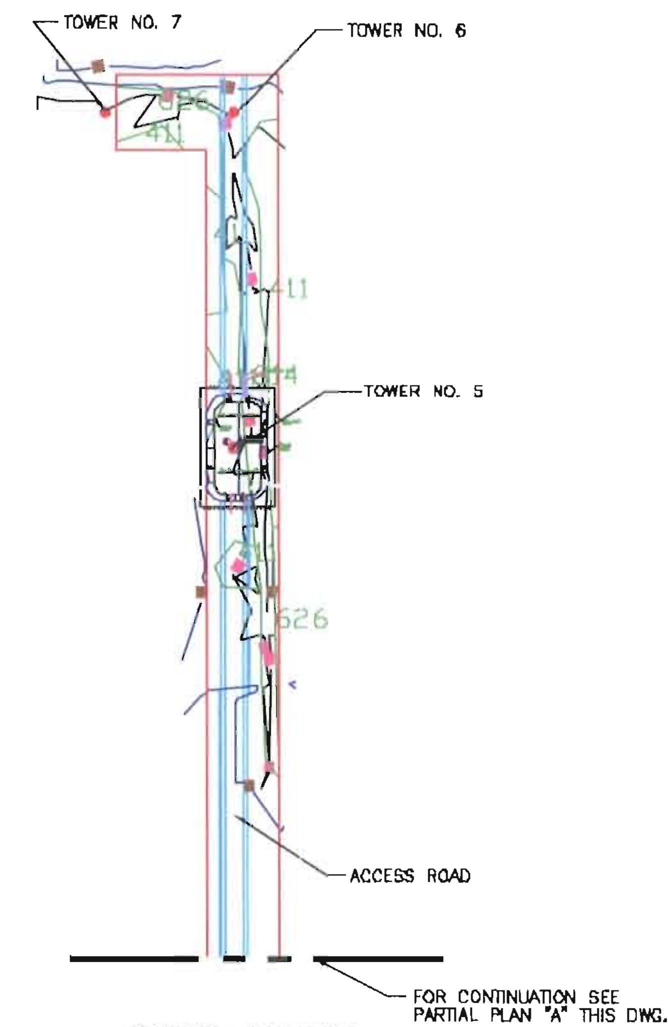
FIGURE E6.
NWI MAP FOR STANTON ENERGY CENTER SITE

Sources: USGS Quads: Oviedo SW and Narcoossee NW, FL, 1980; Orange County NWI data, 2005.

ENGINEERING DRAWINGS



PARTIAL PLAN "A"



PARTIAL PLAN "B"

Southern Company Services, Inc.
FOR
SOUTHERN POWER COMPANY

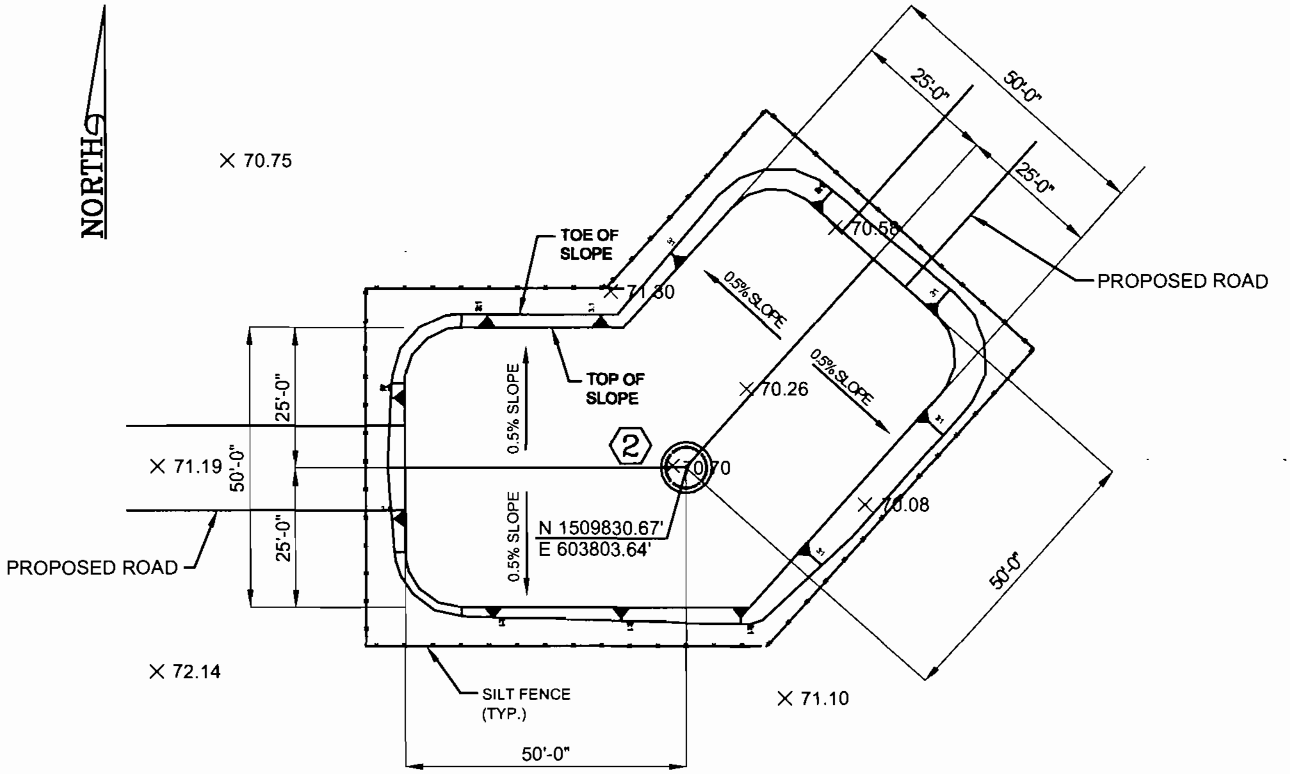
STANTON "B" PROJECT
GENERAL ARRANGEMENT – PLAN
TRANSMISSION LINE RIGHT-OF-WAY
ERP APPLICATION DATA

REVISION	DATE	DESCRIPTION	BY
C	4/28/06	1. ADDED CONTOURS. 2. REVISED ROAD AROUND KEYHOLE PADS. 3. REVISED KEYHOLE PADS.	SHW
B	4/25/06	1. ADDED ACCESS ROAD	SHW
A	04/21/06	ISSUED FOR ERP APPLICATION	SHW

SCALE	PROJ. NO.	DRAWING NUMBER	SH	CONT'D	REV
1"=100'-0"		TAZ-SK-16	1	FINAL	C

S:\Workgroups\SCS Engineering\Technical Services\Power Engineering\C A E projects\Orlando\Rebis\AP97(3D)\Site\TAZ-SK-16C.dwg, 4/28/2006 2:22:13 PM, 1:2.10804

ANSI D 22x34 Acad2004



KEYHOLE PAD DETAIL AT STRUCTURE 2

CUT AND FILL QUANTITIES:

100 YD^3	TOTAL CUT (INCLUDES 100 YD^3 TOPSOIL)
0 YD^3	TOTAL CUT TO USE AS FILL
600 YD^3	TOTAL FILL REQUIRED (INCLUDES 30% COMPACTIC FACTORS)
600 YD^3	TOTAL HAUL-IN (INCLUDES 30% COMPACTION FACTORS

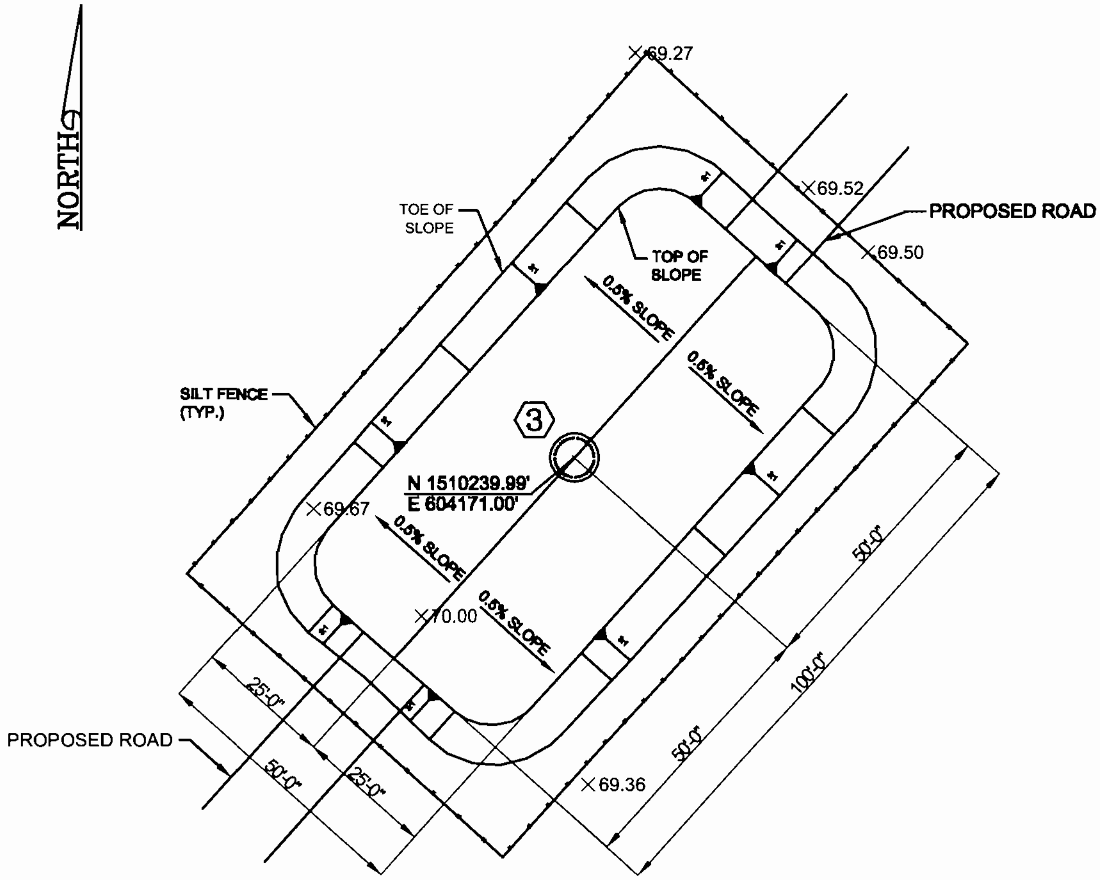
KEYHOLE PAD NOTES:

1. GEOTEXTILE FABRIC SILT FENCE SHALL BE PLACED AS SHOWN IN ACCORDANCE WITH FLORIDA DOT SPECIFICATIONS FOR ROAD AND BRIDGE CONSTRUCTION.
2. THE SILT FENCE SHALL BE INSPECTED AND REPAIRED AS NEEDED AFTER EACH SIGNIFICANT RAINFALL.
3. THE EXISTING TOPSOIL SHALL BE REMOVE TO A MINIMUM DEPTH OF 6" OR AS REQUIRED TO REMOVE ORGANIC MATERIALS. FILL MATERIAL SHALL BE PLACED IN 12" LIFTS AND COMPACTED WITH A VIBRATORY ROLLER TO 95% PROCTOR MAXIMUM DRY DENSITY PER ASTM D698.
4. FILL MATERIAL SHALL BE FROM NATIVE SOIL.
5. KEYHOLE PAD SHALL BE SEEDED AFTER FOUNDATION CONSTRUCTION TO PROVIDE A GRASS SURFACE.

# DWN	-		# DWN	-		# DWN	-	
CHKD	-		CHKD	-		CHKD	-	
APPRVD	-		APPRVD	-		APPRVD	-	
-			-			-		
-			-			-		
-			-			-		
-			-			-		

SOUTHERN POWER FLORIDA, LLC	FACILITY NAME: STANTON ENERGY CENTER UNIT B 230kV T.L.	LOCATION #: -
	TITLE: KEYPAD FOR STRUCTURE #2 -	

DRAWN:	BPO				
CHECKED:	CLA	TYP	- -	A-KEYPAD	SHEET: STR.2
APPROVED:	HVD	SCALE	N/A		REV: 0
DATE:	4/28/2006	BOM	N/A		SUPERSEDES: X-XXXXXX



KEYHOLE PAD DETAIL AT STRUCTURE 3

CUT AND FILL QUANTITIES:

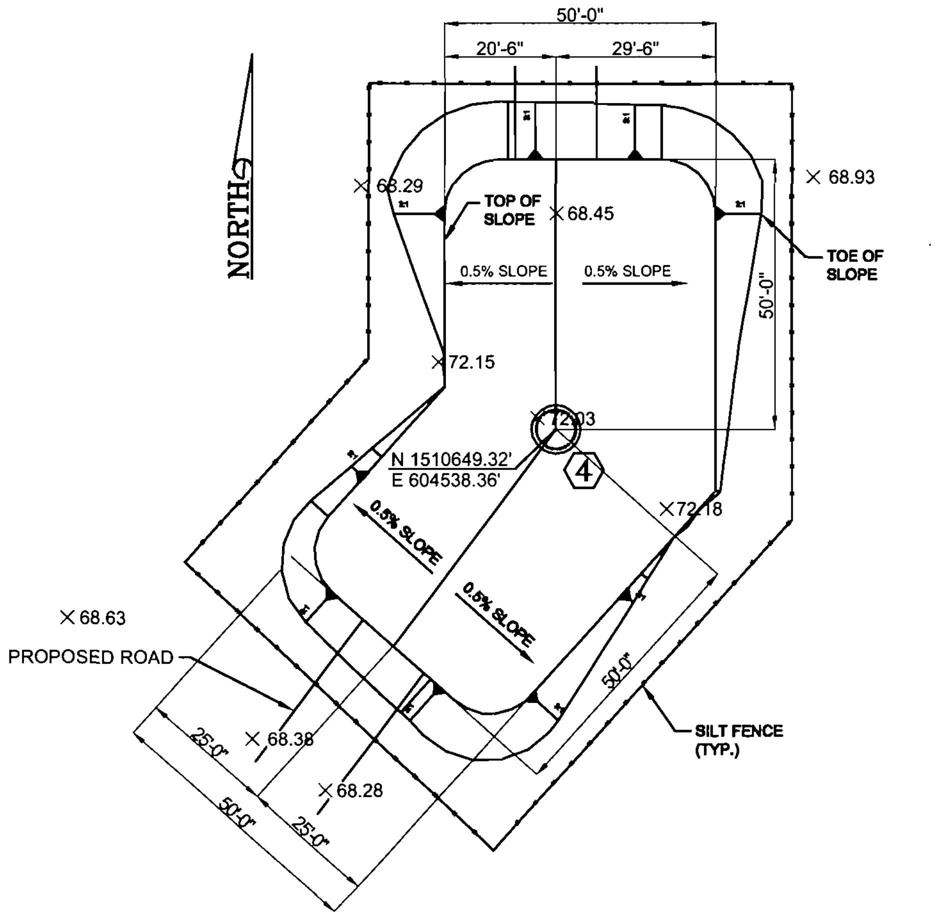
200 YD^3	TOTAL CUT (INCLUDES 200 YD^3 TOPSOIL)
0 YD^3	TOTAL CUT TO USE AS FILL
900 YD^3	TOTAL FILL REQUIRED (INCLUDES 30% COMPACTION FACTORS)
900 YD^3	TOTAL HAUL-IN (INCLUDES 30% COMPACTION FACTORS)

KEYHOLE PAD NOTES:

1. GEOTEXTILE FABRIC SILT FENCE SHALL BE PLACED AS SHOWN IN ACCORDANCE WITH FLORIDA DOT SPECIFICATIONS FOR ROAD AND BRIDGE CONSTRUCTION.
2. THE SILT FENCE SHALL BE INSPECTED AND REPAIRED AS NEEDED AFTER EACH SIGNIFICANT RAINFALL.
3. THE EXISTING TOPSOIL SHALL BE REMOVE TO A MINIMUM DEPTH OF 6" OR AS REQUIRED TO REMOVE ORGANIC MATERIALS. FILL MATERIAL SHALL BE PLACED IN 12" LIFTS AND COMPACTED WITH A VIBRATORY ROLLER TO 95% PROCTOR MAXIMUM DRY DENSITY PER ASTM D698.
4. FILL MATERIAL SHALL BE FROM NATIVE SOIL.
5. KEYHOLE PAD SHALL BE SEEDED AFTER FOUNDATION CONSTRUCTION TO PROVIDE A GRASS SURFACE.

# DWN	-		# DWN	-		# DWN	-	
CHKD	-		CHKD	-		CHKD	-	
APPRVD	-		APPRVD	-		APPRVD	-	
-			-			-		
-			-			-		
-			-			-		
-			-			-		

SOUTHERN POWER FLORIDA, LLC	FACILITY NAME: STANTON ENERGY CENTER UNIT B 230kV T.L.		LOCATION #: -
	TITLE: KEYPAD FOR STRUCTURE #3 -		
DRAWN: BPO	TYP: - -	A-KEYPAD	SHEET: STR 3
CHECKED: CLA	SCALE: N/A		REV: 0
APPROVED: HVD	BOM: N/A		SUPERSEDES: X-XXXXXX
DATE: 4/28/2006			



KEYHOLE PAD DETAIL AT STRUCTURE 4

CUT AND FILL QUANTITIES:

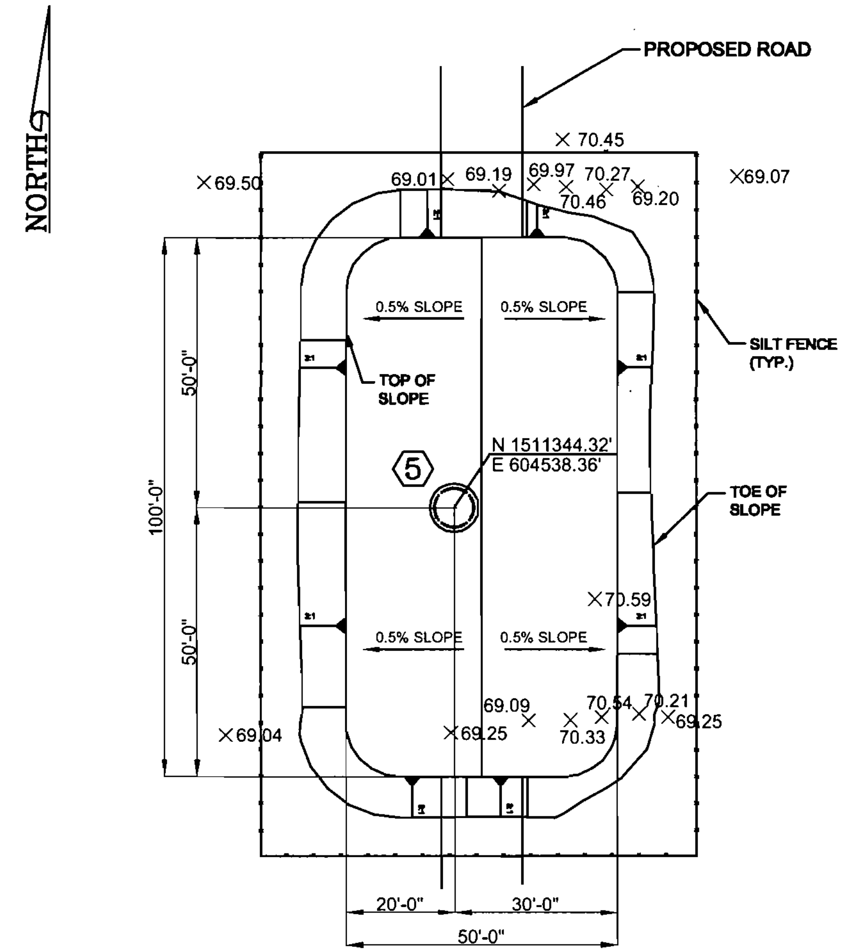
200 YD^3	TOTAL CUT (INCLUDES 200 YD^3 TOPSOIL)
0 YD^3	TOTAL CUT TO USE AS FILL
1050 YD^3	TOTAL FILL REQUIRED (INCLUDES 30% COMPACTION FACTORS)
1050 YD^3	TOTAL HAUL-IN (INCLUDES 30% COMPACTION FACTORS)

KEYHOLE PAD NOTES:

1. GEOTEXTILE FABRIC SILT FENCE SHALL BE PLACED AS SHOWN IN ACCORDANCE WITH FLORIDA DOT SPECIFICATIONS FOR ROAD AND BRIDGE CONSTRUCTION.
2. THE SILT FENCE SHALL BE INSPECTED AND REPAIRED AS NEEDED AFTER EACH SIGNIFICANT RAINFALL.
3. THE EXISTING TOPSOIL SHALL BE REMOVE TO A MINIMUM DEPTH OF 6" OR AS REQUIRED TO REMOVE ORGANIC MATERIALS. FILL MATERIAL SHALL BE PLACED IN 12" LIFTS AND COMPACTED WITH A VIBRATORY ROLLER TO 95% PROCTOR MAXIMUM DRY DENSITY PER ASTM D698.
4. FILL MATERIAL SHALL BE FROM NATIVE SOIL.
5. KEYHOLE PAD SHALL BE SEEDED AFTER FOUNDATION CONSTRUCTION TO PROVIDE A GRASS SURFACE.

# DWN	-		# DWN	-		# DWN	-	
CHKD	-		CHKD	-		CHKD	-	
APPRVD	-		APPRVD	-		APPRVD	-	
- - - -			- - - -			- - - -		

SOUTHERN POWER FLORIDA, LLC	FACILITY NAME STANTON ENERGY CENTER B 230kV T.L.		LOCATION # -
	TITLE KEYPAD FOR STRUCTURE #4 -		
DRAWN: BPO			
CHECKED: CLA	TYP - -	A-KEYPAD	SHEET STR 4 / REV 0
APPROVED: HVD	SCALE N/A		
DATE: 4/28/2006	BOM N/A		SUPERSEDES: X-XXXXXX



KEYHOLE PAD DETAIL
AT STRUCTURE 5

CUT AND FILL QUANTITIES:

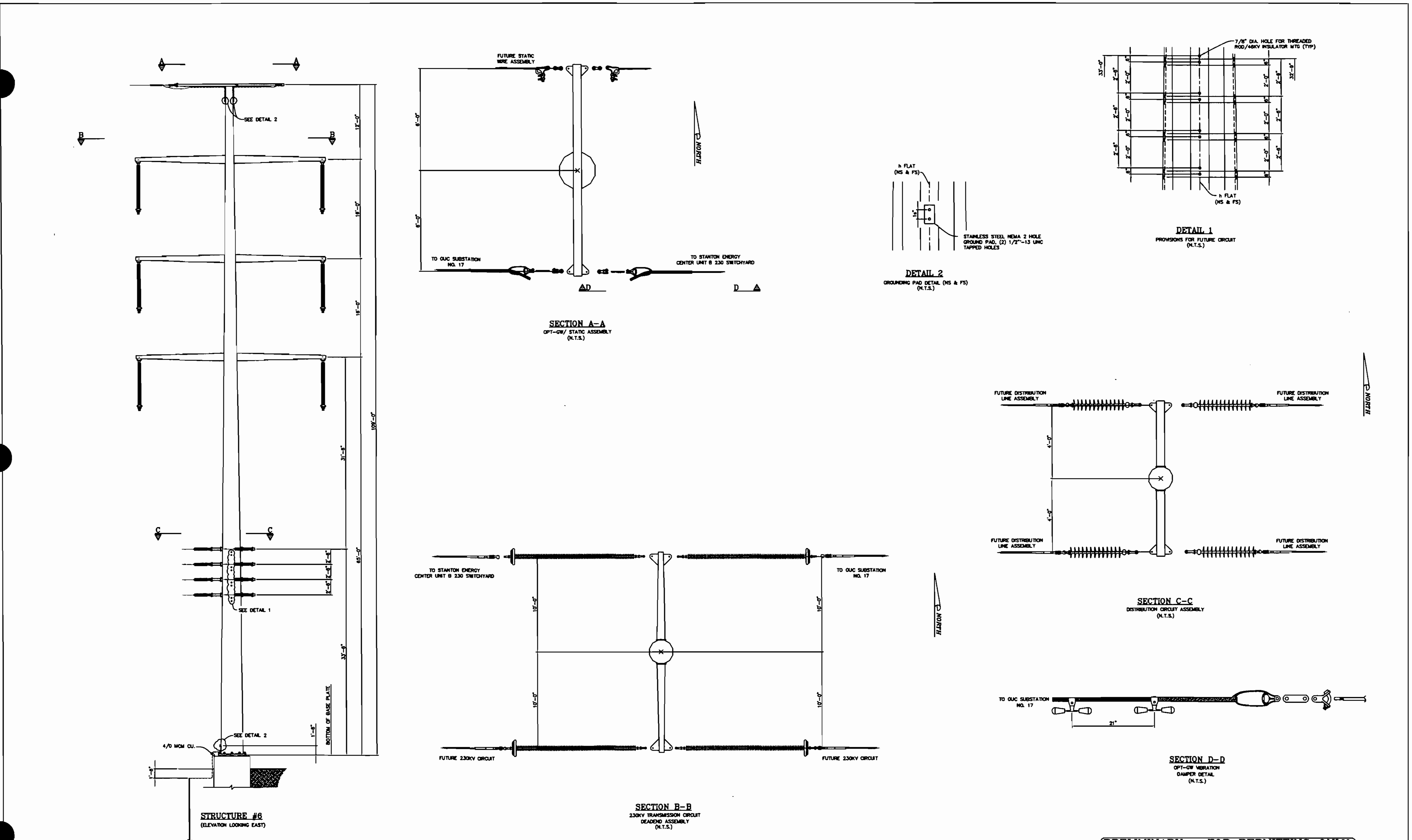
200 YD^3	TOTAL CUT (INCLUDES 200 YD^3 TOPSOIL)
0 YD^3	TOTAL CUT TO USE AS FILL
900 YD^3	TOTAL FILL REQUIRED (INCLUDES 30% COMPACTION FACTORS)
900 YD^3	TOTAL HAUL-IN (INCLUDES 30% COMPACTION FACTORS)

KEYHOLE PAD NOTES:

1. GEOTEXTILE FABRIC SILT FENCE SHALL BE PLACED AS SHOWN IN ACCORDANCE WITH FLORIDA DOT SPECIFICATIONS FOR ROAD AND BRIDGE CONSTRUCTION.
2. THE SILT FENCE SHALL BE INSPECTED AND REPAIRED AS NEEDED AFTER EACH SIGNIFICANT RAINFALL.
3. THE EXISTING TOPSOIL SHALL BE REMOVE TO A MINIMUM DEPTH OF 6" OR AS REQUIRED TO REMOVE ORGANIC MATERIALS. FILL MATERIAL SHALL BE PLACED IN 12" LIFTS AND COMPACTED WITH A VIBRATORY ROLLER TO 95% PROCTOR MAXIMUM DRY DENSITY PER ASTM D698.
4. FILL MATERIAL SHALL BE FROM NATIVE SOIL.
5. KEYHOLE PAD SHALL BE SEEDED AFTER FOUNDATION CONSTRUCTION TO PROVIDE A GRASS SURFACE.

# DWN	-		# DWN	-		# DWN	-	
CHKD	-		CHKD	-		CHKD	-	
APPRVD	-		APPRVD	-		APPRVD	-	
- - - -			- - - -			- - - -		

SOUTHERN POWER FLORIDA, LLC	FACILITY NAME: STANTON ENERGY CENTER UNIT B 230kV T.L.		LOCATION #: -
	TITLE: KEYPAD FOR STRUCTURE #5 -		
DRAWN: BPO			
CHECKED: CLA	TYP - -	A-KEYPAD	SHEET: STR 5 / REV: 0
APPROVED: HVD	SCALE N/A		
DATE: 4/28/2006	BOM N/A		SUPERSEDES: X-XXXXXX



(PRELIMINARY – FOR PERMITTING ONLY)

# DWN –	-/-/200-	# DWN	-/-/200-	# DWN –	-/-/200-	A DWN –	-/-/200-	MENS #
CHKD –	-/-/200-	CHKD	-/-/200-	CHKD –	-/-/200-	CHKD –	-/-/200-	
APPRVD –	-/-/200-	APPRVD	-/-/200-	APPRVD –	-/-/200-	APPRVD –	-/-/200-	SERIAL #
						ISSUED FOR PERMITTING		PO #

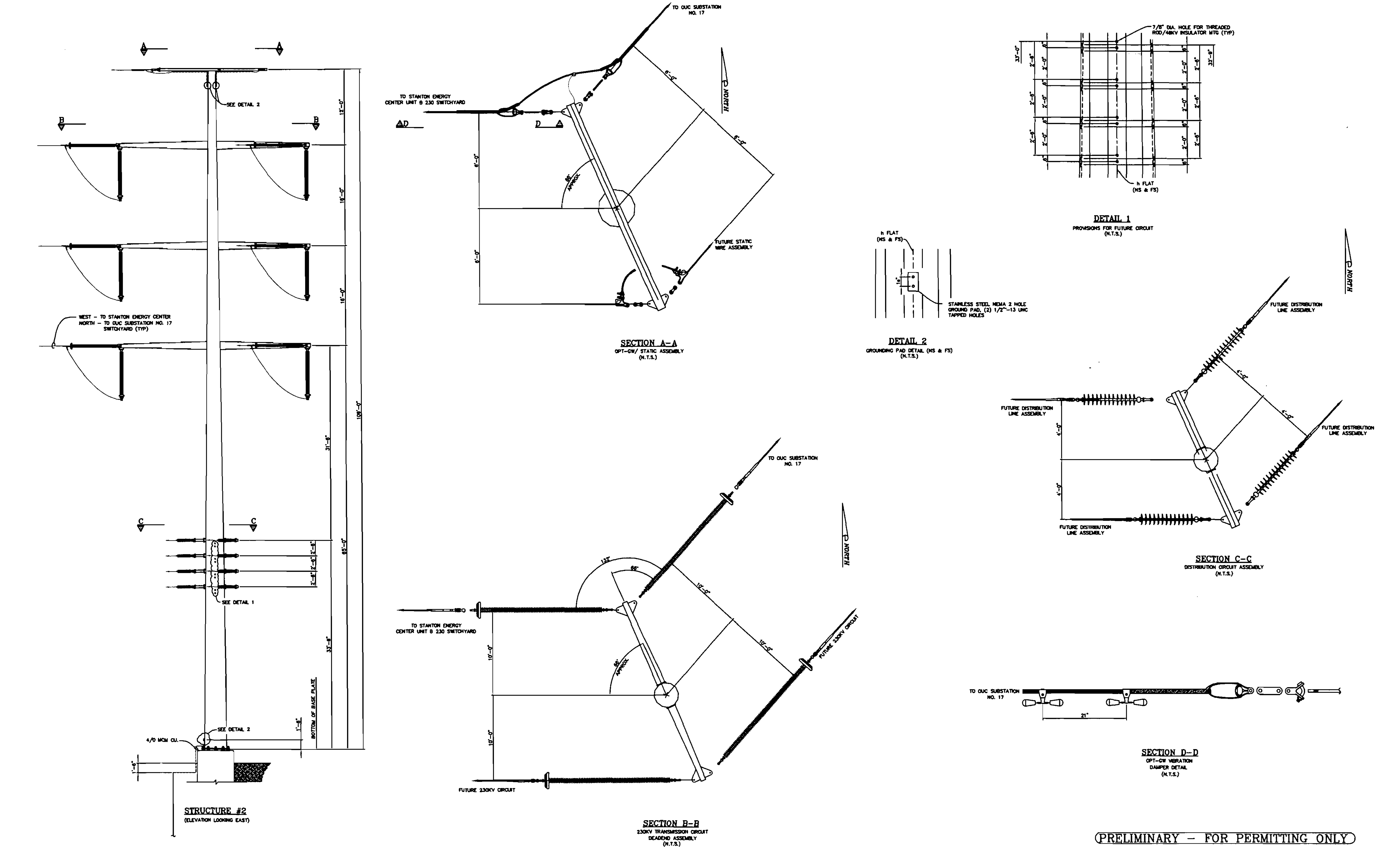
DRAWN:	BPO
CHECKED:	HVD/ MTM
APPROVED:	HVD/ MTM
DATE:	4/20/06

SOUTHERN POWER FLORIDA, LLC LOCATION #

STANTON ENERGY CENTER UNIT B 230 kV SWITCHYARD & T.L.
STRUCTURE #1

SC TYP NTS

STA B _ SHEET STR 1 REV A



PRELIMINARY – FOR PERMITTING ONLY

ISSUED FOR PERMITTING

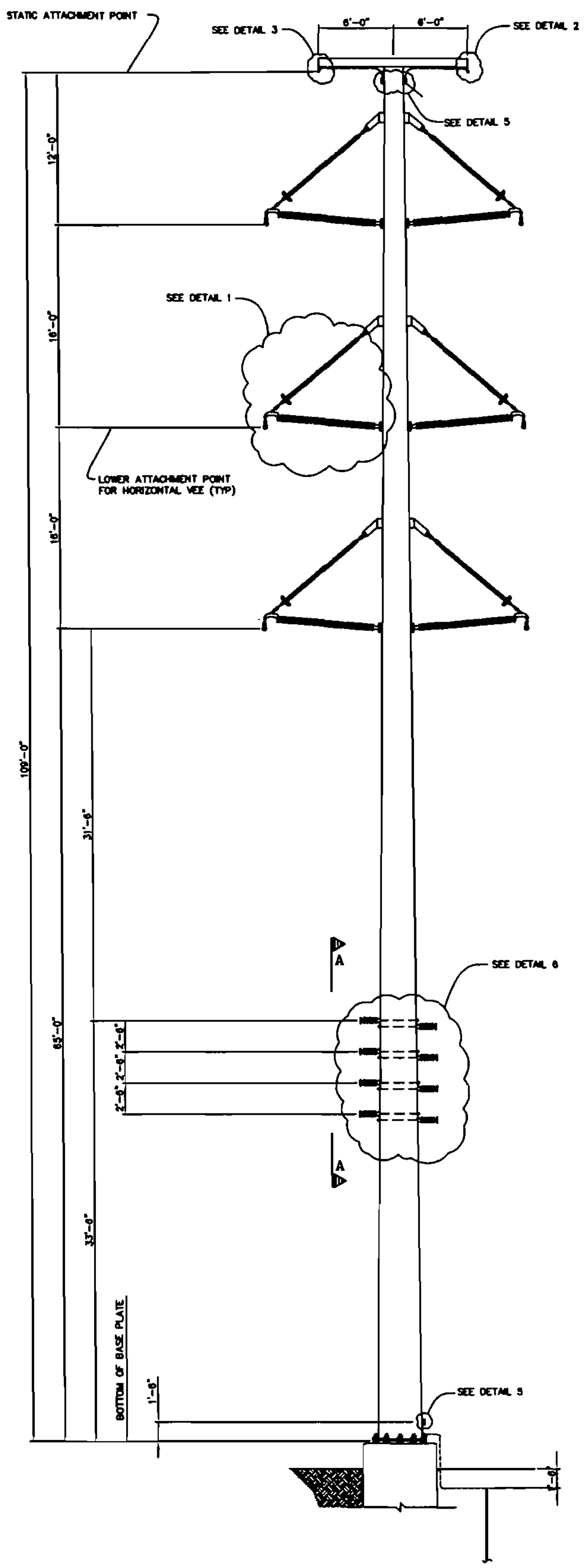
SOUTHERN POWER FLORIDA, LLC

STANTON ENERGY CENTER UNIT B 230 kV SWITCHYARD & T.L.
STRUCTURE #2

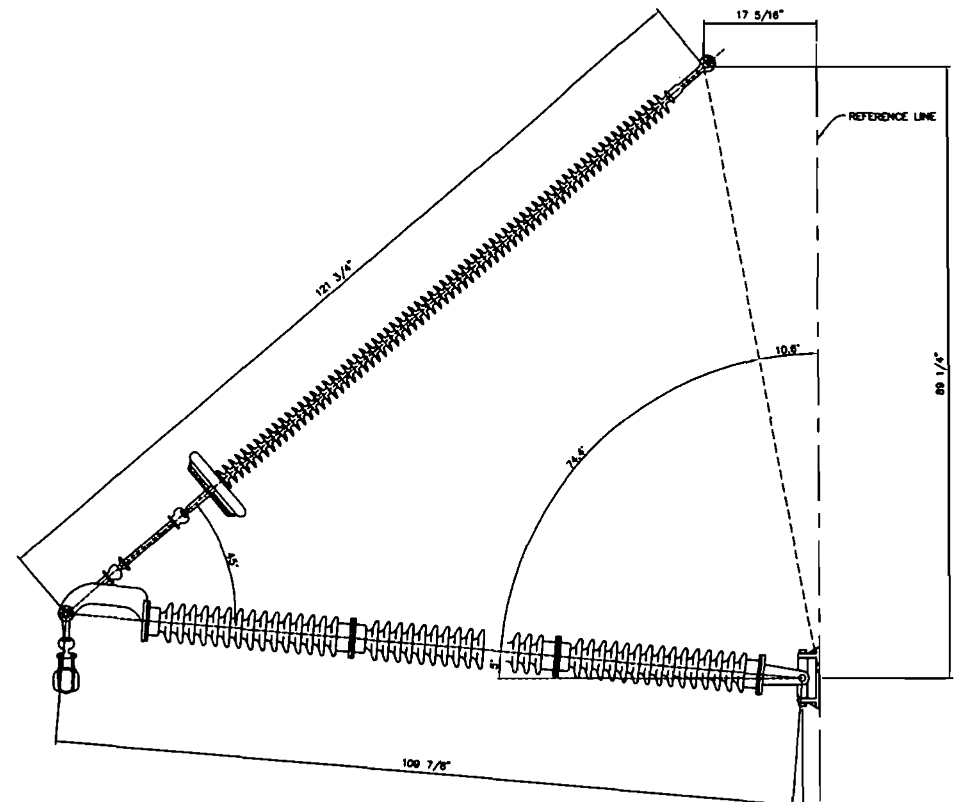
DRAWN:	BPO
CHECKED:	HVD/ MTM
APPROVED:	HVD/ MTM
DATE:	4/20/06

NTS

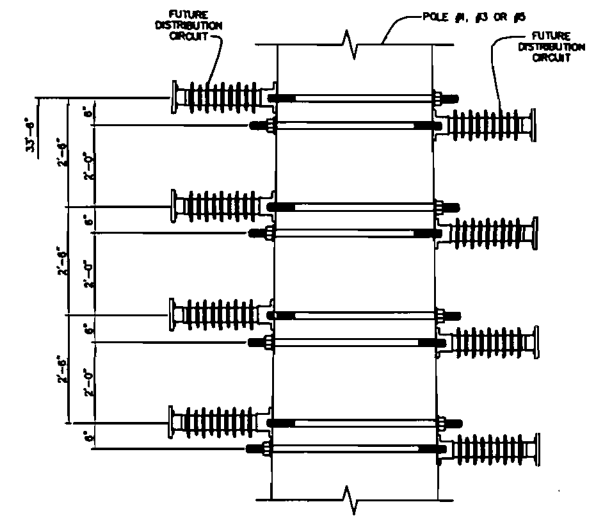
STA B_ STR 2 A



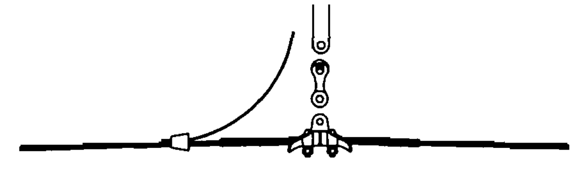
STRUCTURES #3 & #5



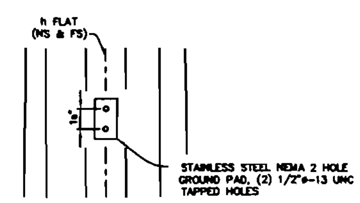
DETAIL 1
HORIZONTAL VEE ASSEMBLY



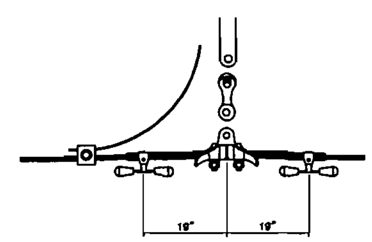
DETAIL 6
DISTRIBUTION LINE MOUNTING
(N.T.S.)



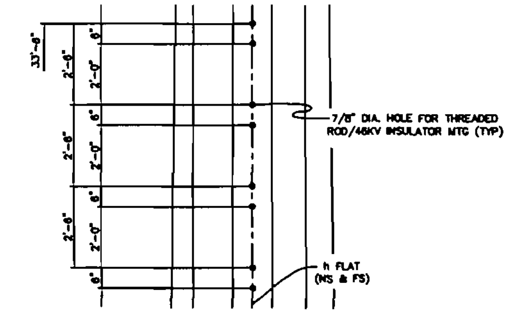
DETAIL 2
7-#8 ALUMOWELD STATIC ASSEMBLY
(N.T.S.)



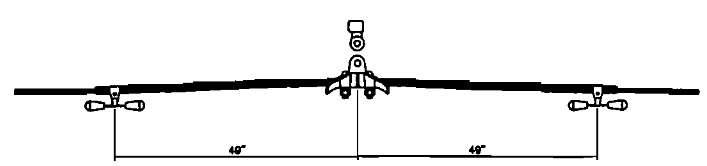
DETAIL 5
GROUNDING PAD DETAIL (NS & FS)
(N.T.S.)



DETAIL 3
OPT-GW ASSEMBLY
(N.T.S.)



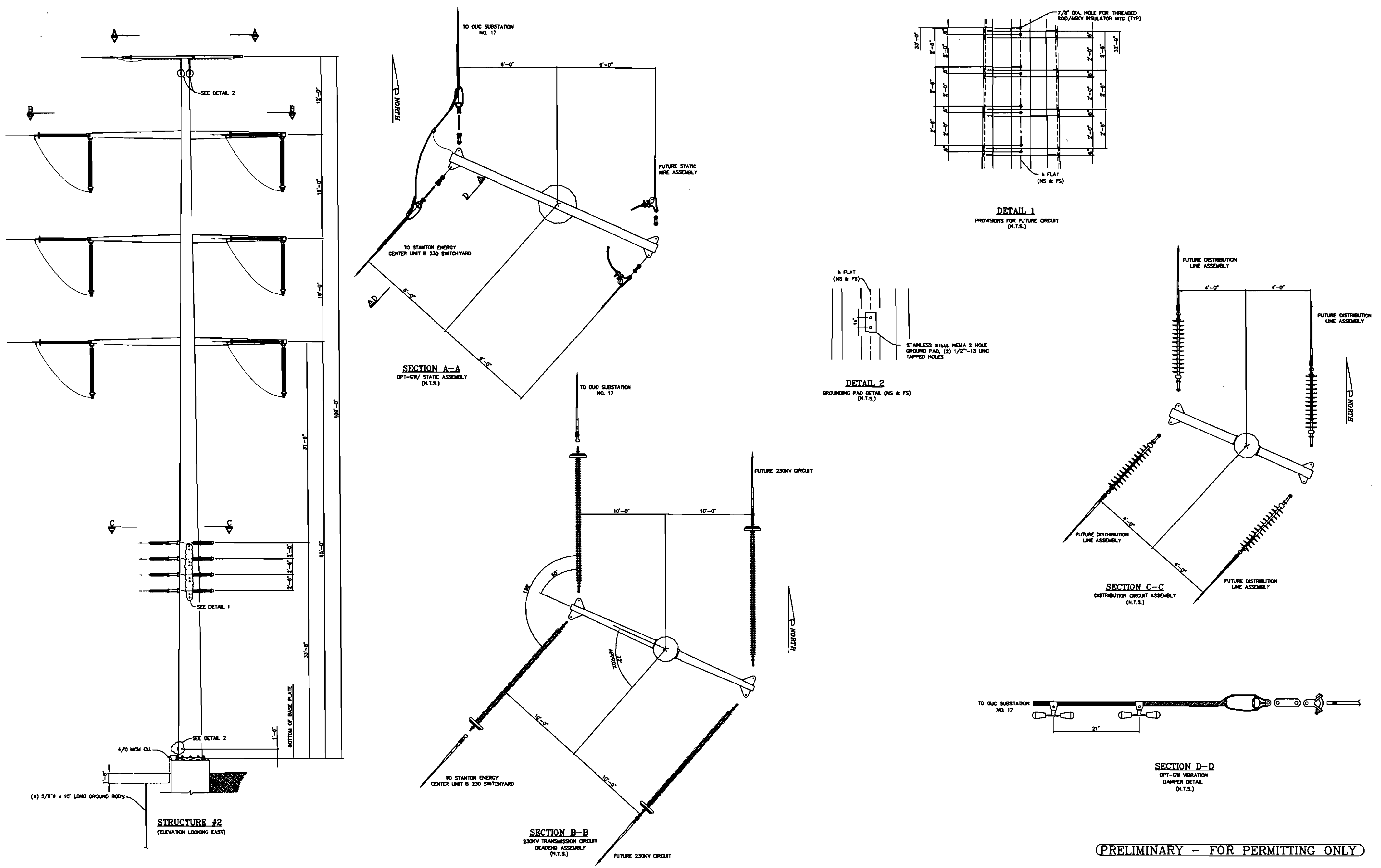
SECTION A-A
PROVISIONS FOR DISTRIBUTION CIRCUIT
(N.T.S.)



DETAIL 4
1272 ACSS/TW CONDUCTOR ASSEMBLY
(N.T.S.)

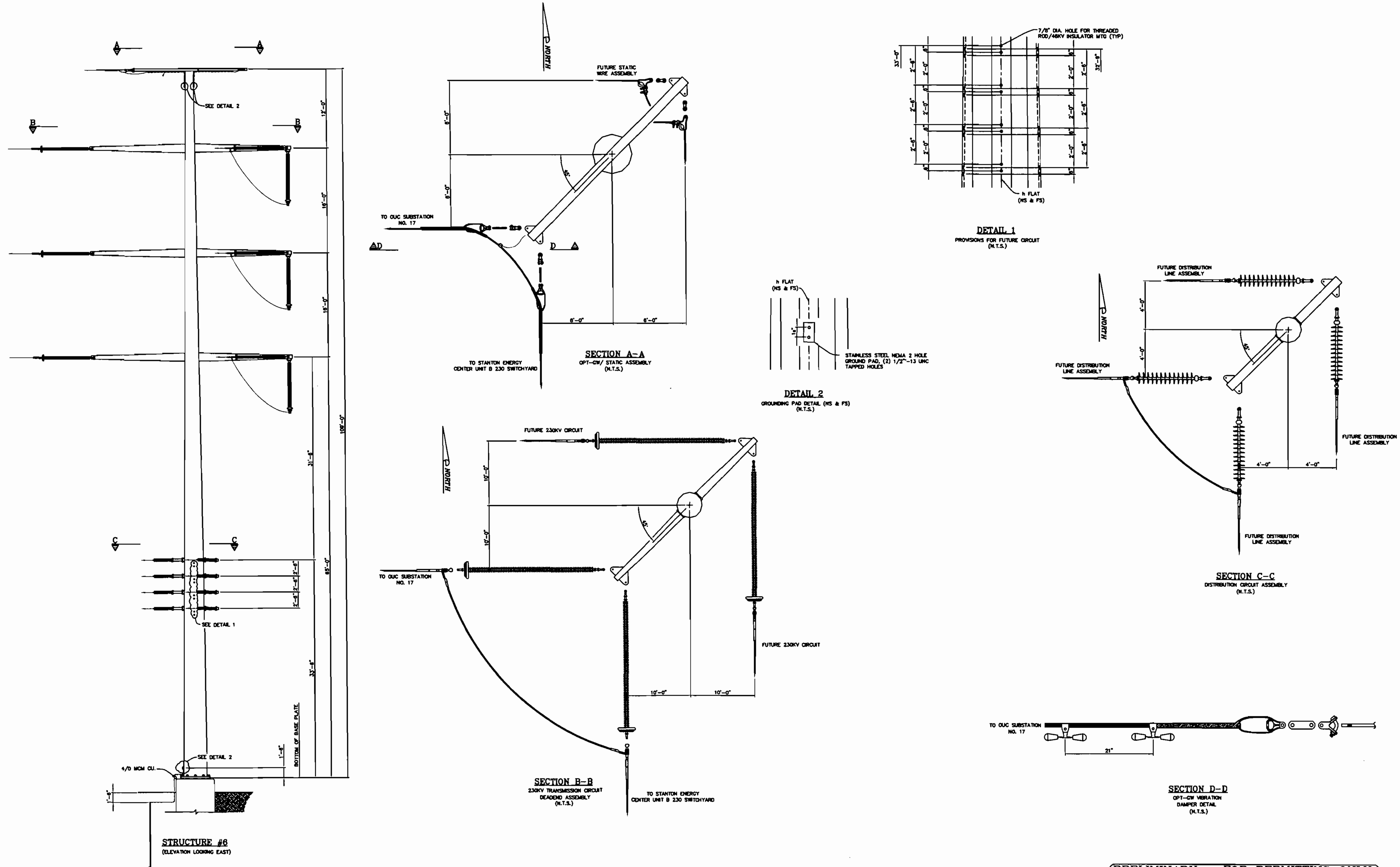
PRELIMINARY – FOR PERMITTING ONLY

# DWN– -/-/200-	# DWN -/-/200-	# DWN– -/-/200-	A DWN– -/-/200-	MENS #		SOUTHERN POWER FLORIDA, LLC	LOCATION #
CHKD– -/-/200-	CHKD -/-/200-	CHKD– -/-/200-	CHKD– -/-/200-			STANTON ENERGY CENTER UNIT B 230 kV SWITCHYARD & T.L. STRUCTURE #3 & #5	
APPRVD– -/-/200-	APPRVD -/-/200-	APPRVD– -/-/200-	APPRVD– -/-/200- ISSUED FOR PERMITTING	SERIAL #	DRAWN: BPO		
					CHECKED: HVD/ MTM		
				PO #	APPROVED: HVD/ MTM	NTS	STA B_STR 3&5 A
					DATE: 4/20/06		SHEET REV



(PRELIMINARY – FOR PERMITTING ONLY)

# DWN– -/-/200–	# DWN -/-/200–	# DWN– -/-/200–	A DWN– -/-/200–	MENS #		SOUTHERN POWER FLORIDA, LLC	LOCATION #
CHKD– -/-/200–	CHKD -/-/200–	CHKD– -/-/200–	CHKD– -/-/200–			STANTON ENERGY CENTER UNIT B 230 kV SWITCHYARD & T.L. STRUCTURE #4	
APPRVD– -/-/200–	APPRVD -/-/200–	APPRVD– -/-/200–	APPRVD– -/-/200– ISSUED FOR PERMITTING	SERIAL #	DRAWN: BPO		
				PO #	CHECKED: HVD/ MTM; APPROVED: HVD/ MTM; DATE: 4/20/06	SC TYP NTS	STA B SHEET STR 4 REV A



PRELIMINARY – FOR PERMITTING ONLY

# DWN– -/-/200-	# DWN -/-/200-	# DWN– -/-/200-	A DWN– -/-/200-	MENS #
CHKD– -/-/200-	CHKD -/-/200-	CHKD– -/-/200-	CHKD– -/-/200-	SERIAL #
APPRVD– -/-/200-	APPRVD -/-/200-	APPRVD– -/-/200-	APPRVD– -/-/200-	PO #
			ISSUED FOR PERMITTING	

SOUTHERN POWER FLORIDA, LLC

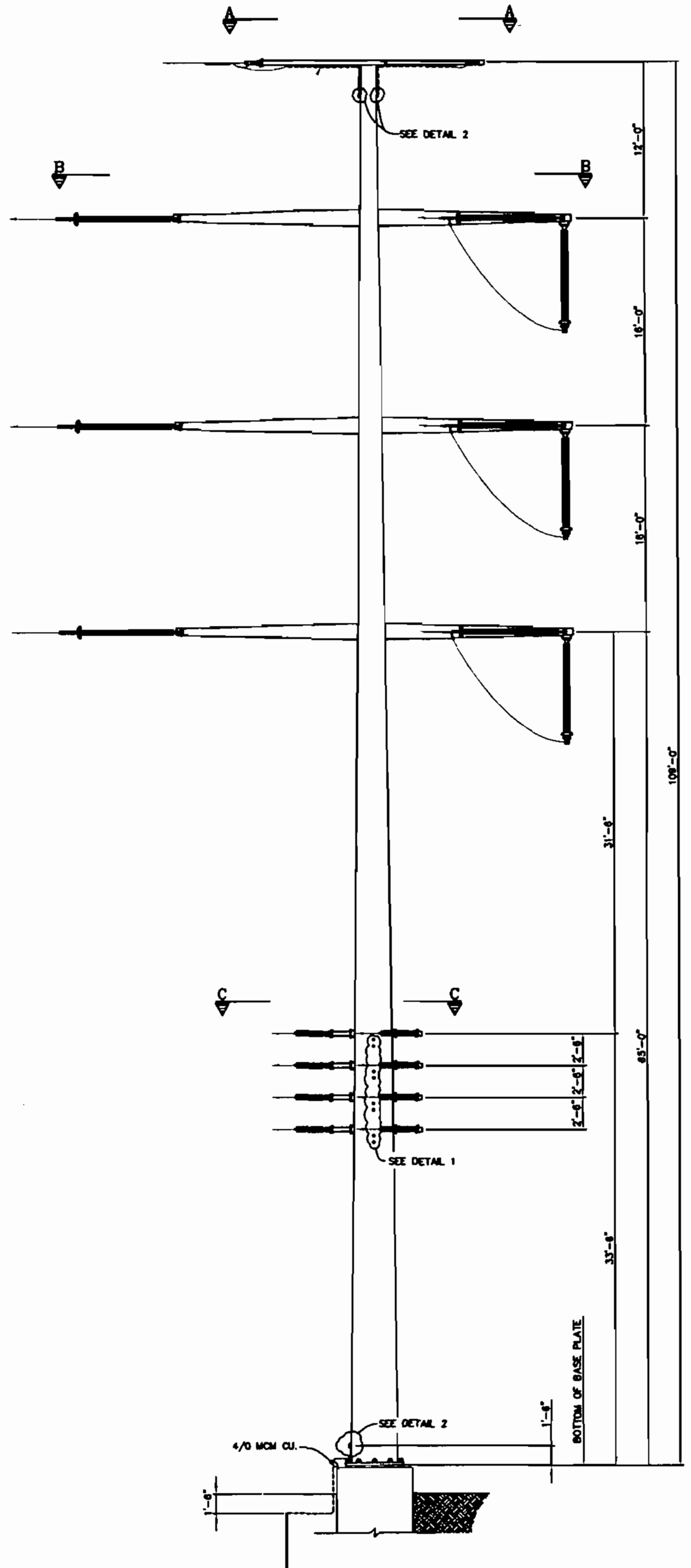
STANTON ENERGY CENTER UNIT B 230 kV SWITCHYARD & T.L.
STRUCTURE #6

LOCATION #

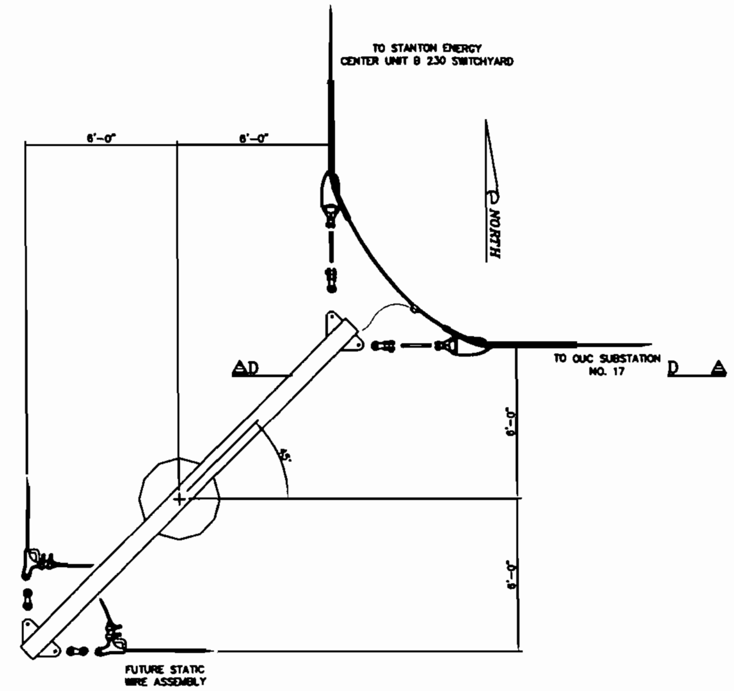
DRAWN:	BPO
CHECKED:	HVD/ MTM
APPROVED:	HVD/ MTM
DATE:	4/20/06

SCALE: NTS

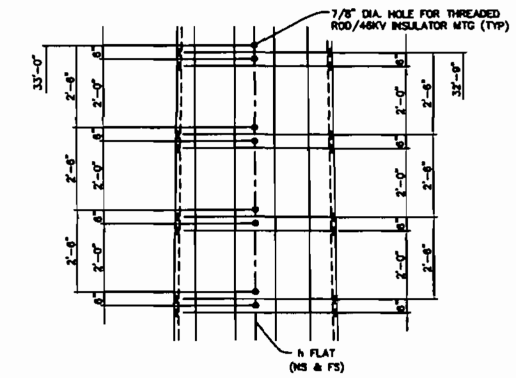
STA B SHEET STR 6 REV A



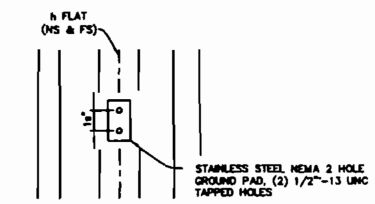
STRUCTURE #7
(ELEVATION LOOKING EAST)



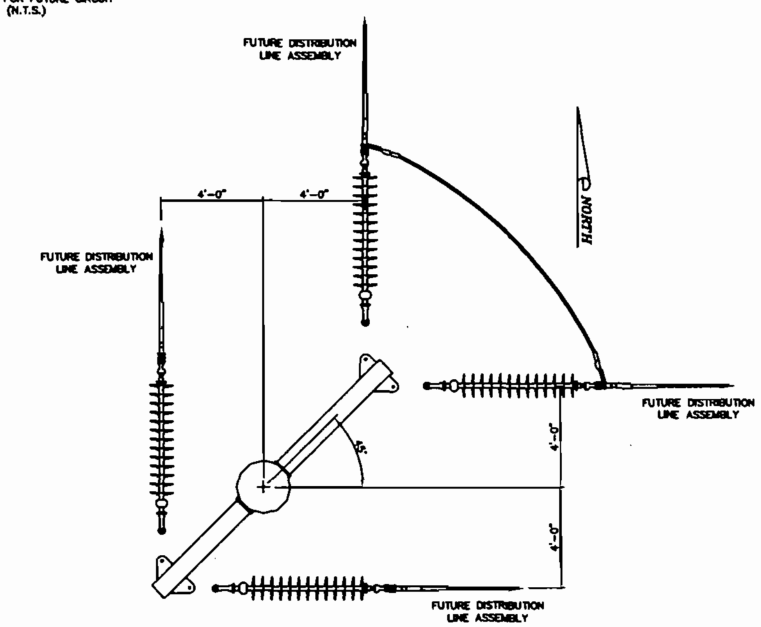
SECTION A-A
OPT-GW/ STATIC ASSEMBLY
(N.T.S.)



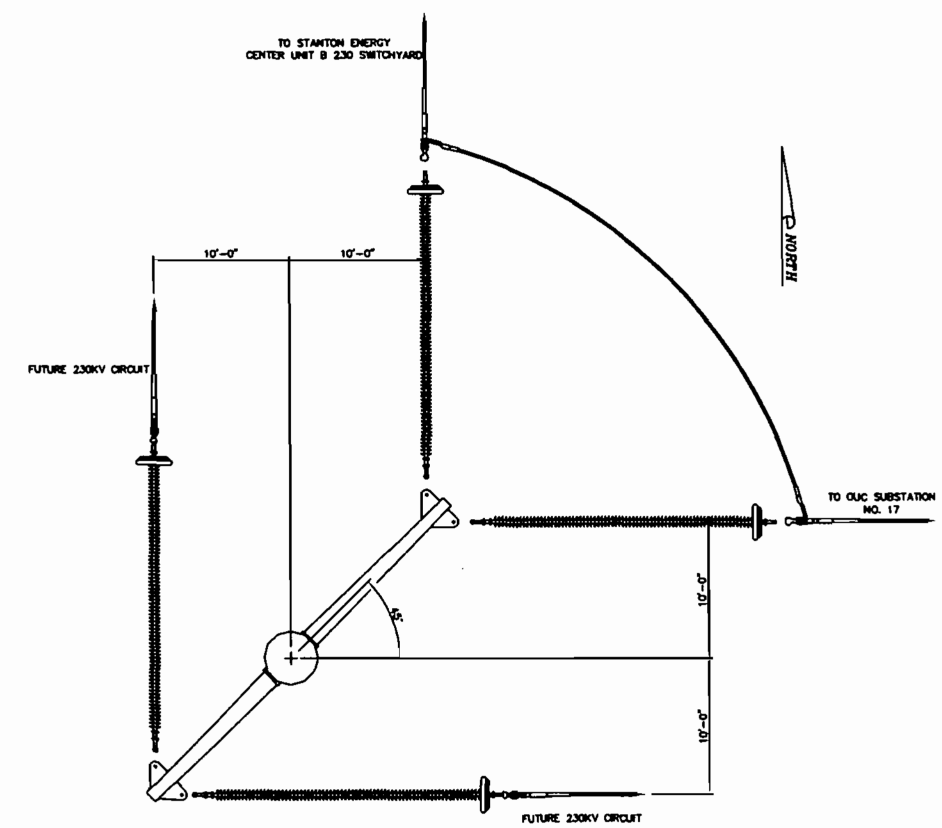
DETAIL 1
PROVISIONS FOR FUTURE CIRCUIT
(N.T.S.)



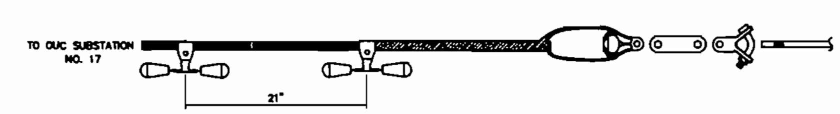
DETAIL 2
GROUNDING PAD DETAIL (NS & FS)
(N.T.S.)



SECTION C-C
DISTRIBUTION CIRCUIT ASSEMBLY
(N.T.S.)



SECTION B-B
230KV TRANSMISSION CIRCUIT DEADEND ASSEMBLY
(N.T.S.)



SECTION D-D
OPT-GW VIBRATION DAMPER DETAIL
(N.T.S.)

(PRELIMINARY – FOR PERMITTING ONLY)

# DWN	-/-/200-	# DWN	-/-/200-	# DWN	-/-/200-	A DWN	-/-/200-	MEMS #
CHKD	-/-/200-	CHKD	-/-/200-	CHKD	-/-/200-	CHKD	-/-/200-	
APPRVD	-/-/200-	APPRVD	-/-/200-	APPRVD	-/-/200-	APPRVD	-/-/200-	SERIAL #
						ISSUED FOR PERMITTING		PO #

SOUTHERN POWER FLORIDA, LLC

LOCATION #

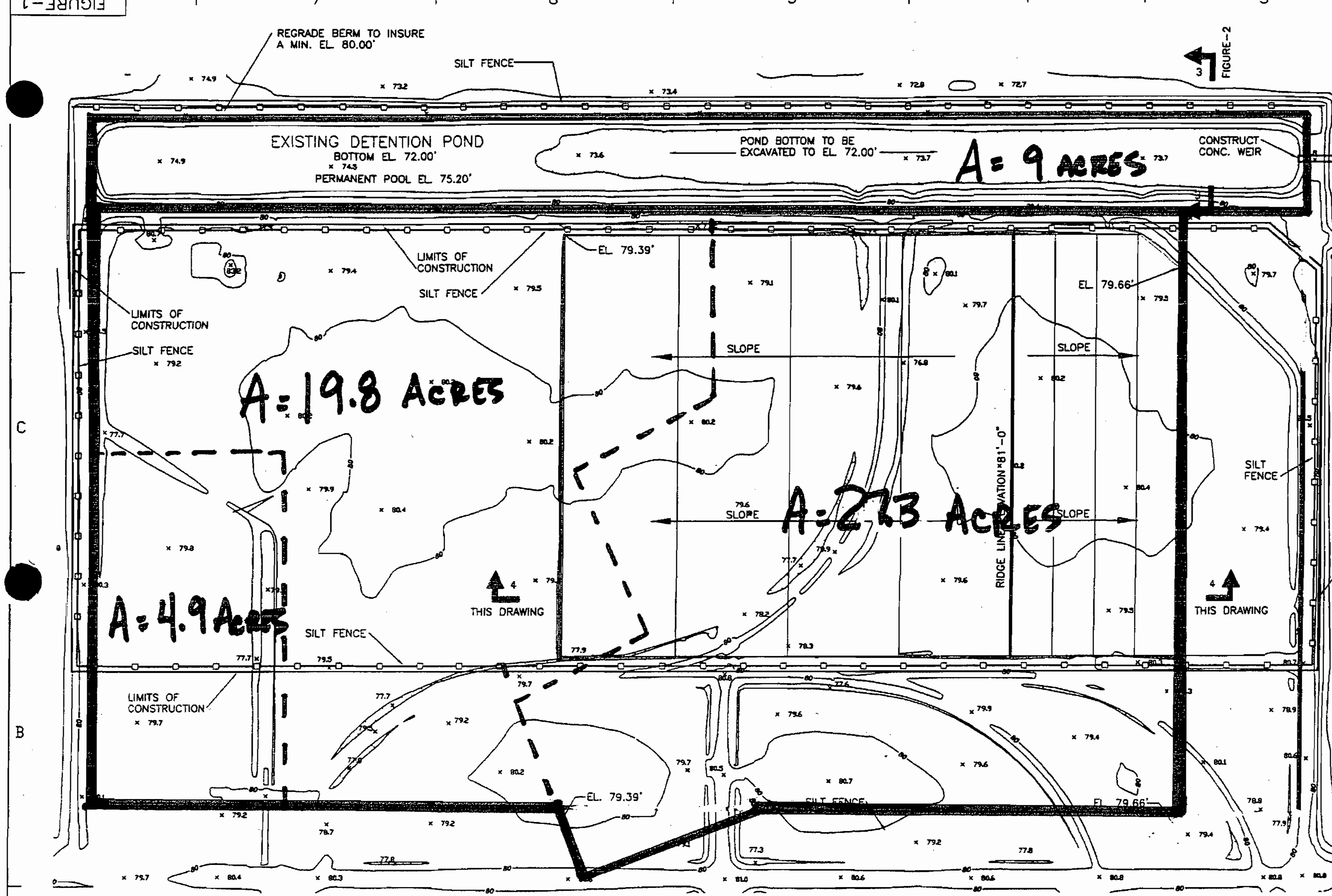
STANTON ENERGY CENTER UNIT B 230 kV SWITCHYARD & T.L.
STRUCTURE #7

DRAWN:	BPO
CHECKED:	HVD/ MTM
APPROVED:	HVD/ MTM
DATE:	4/20/06

SCALE: NTS

STA B_ STR 7 — SHEET | REV: A

Attachment CENTRAL FDEP-D.1



EROSION CONTROL NOTES:

1. GEOTEXTILE FABRIC SILT FENCE SHALL BE PLACED ALONG PROJECT BOUNDARY IN ACCORDANCE WITH FLORIDA DOT STANDARD SPECIFICATIONS FOR ROAD AND BRIDGE CONSTRUCTION.
2. ALL EROSION CONTROL AND SEDIMENT TRAPPING DEVICES SHALL BE INSPECTED AND REPAIRED OR REPLACED AS NEEDED AFTER EACH SIGNIFICANT RAINFALL. EARTHWORK CONTRACTOR WHILE ON SITE, SHALL BE RESPONSIBLE FOR MAINTAINING EROSION CONTROL DEVICES. BEFORE CONTRACTOR LEAVES THE SITE ALL EROSION CONTROL DEVICES SHALL BE INSPECTED AND APPROVED BY THE OWNER.
3. TOPSOIL SHALL BE STRIPPED FOR ALL PERMANENT AND TEMPORARY ROADS, CONSTRUCTION LAYDOWN, CONSTRUCTION AND PERMANENT PARKING AREAS, SWITCHYARD, AND PLANT AREA CONTAINED BY PERMANENT PLANT ACCESS ROADS.
4. ENTIRE SITE INSIDE PROJECT BOUNDARY SHALL BE CLEARED AND GRUBBED.
5. DUST SHALL BE CONTROLLED ON THE ENTRANCE ROADS AND PLANT ROADS BY SPRINKLING WITH WATER.

POND NOTES

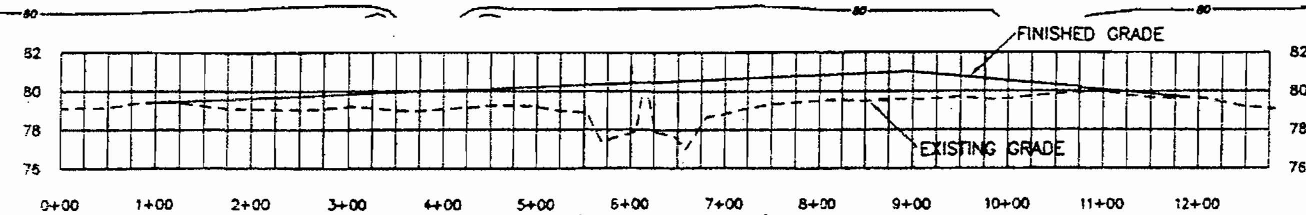
1. ALL INTERIOR SIDE SLOPES TO BE DISTURBED TO THE LEAST EXTENT POSSIBLE.
2. ANY INTERIOR SIDE SLOPES DISTURBED DURING CONSTRUCTION SHALL BE REGRADED AT 4:1 (MAX)
3. THE EXISTING DISCHARGE STRUCTURE SHALL BE REMOVED AND REPLACED (SEE NEW WEIR PLAN AND SECTIONS ON DRAWING FIGURE-2.
4. THE LITTORAL ZONE SHALL BE REPLANTED TO PRE-CONSTRUCTION CONDITION PRIOR TO PROJECT COMPLETION. EVERY EFFORT SHALL BE MADE TO AVOID DISRUPTION OF THESE AREAS DURING CONSTRUCTION.

N

GRAPHIC SCALE

100 0 100 200

SCALE IN FEET



SECTION 4-4 (LOOKING NORTH)

CAD FIGURE-1.DWG
AutoCad | SHW-20001

Southern Company Services, Inc.
FOR
SOUTHERN COMPANY GENERATION
STANTON ENERGY CENTER - UNIT A
1-2x1 COMBINED CYCLE BLOCK
GRADING AND DRAINAGE PLAN

REVISION	DATE	DESCRIPTION	BY
B	02/09/01	CHANGED AREA OF LIMITS OF CONSTRUCTION	CMF
A	01/05/01	ISSUED FOR REVIEW	SHW

DESIGNED | DRAWN SHW | CHECKED
SCALE | PROJECT I.D. | DRAWING NUMBER FIGURE-1 | REV. B

ATTACHMENT
STANTON UNIT 3 STORM WATER CALCULATIONS

Design Requirements:

Design Rainfall Events: Mean Annual = 4.4 inches
25 Year – 24 Hour = 8.7 inches
100 Year – 24 Hour = 10.8 inches

Design Rainfall Distribution: SCS Type II

Pond Sizing / Treatment Volumes:

Directly Connected Impervious Area (DCIA):

DCIA = pond area = 393,621 square feet = 9 acres

$$\%DCIA = \frac{9.0}{52.0 + 9.0} = 14.75\%$$

Treatment Volume:

The design treatment volume shall be the greater of the following:

1) 1" over entire treatment area

Area = 52.0 acres

$$Volume_1 = 52.0 \text{ acres} \times \frac{43{,}560 \text{ ft}^2}{\text{acre}} \times 1\text{" runoff} \times \frac{1'}{12"}$$

$Volume_1 = 188{,}760 \text{ ft}^3$

2) 2.5" over contributing impervious areas

Total impervious area = 41.2 acres

$$Volume_2 = 41.2 \text{ acres} \times \frac{43{,}560 \text{ ft}^2}{\text{acre}} \times 2.5\text{" runoff} \times \frac{1'}{12"}$$

$Volume_2 = 373{,}890 \text{ ft}^3$

Required treatment volume = 373,890 ft^3

Stage-Area Relationship:

Elevation	Area (square feet)	Area (acres)
73.0	245,525	5.6
75.0	281,781	6.5
77.0	318,549	7.3
80.0	374,661	8.6

Groundwater table and permanent pool elevation: 75.20 feet

Depth of treatment volume:

$$\frac{373{,}890 \text{ ft}^3}{(1{,}320{,}825 \text{ ft}^3 - 734{,}254 \text{ ft}^3)} = 0.64 \text{ feet}$$

Elevation of treatment volume = 75.84 feet

Recovery Time:

The outfall structure will draw down 50 percent of the required treatment volume between 48 and 60 hours.

Outlet Structure:

Q = Rate of discharge (cfs)

A = Orifice area (ft^2)

g = Gravitational constant = (32.2 ft/sec^2)

h = Depth of Water above the flow line of the orifice

C = Orifice coeffcient (assumed 0.6)

Treatment volume = 373,890 ft^3

The average discharge rate required to draw down half the treatment volume in a 60 hours is given by:

$$Q = \frac{186{,}945 \text{ ft}^3}{2\,(60 \text{ hr})(3{,}600 \text{ sec/hr})} = 0.43 \text{ cfs}$$

The depth of water (h) set to the average depth above the flow line between the top of the treatment volume and the stage at which half of the treatment volume has been released is:

$$h = \frac{0.64 + 0.32}{2} = 0.48 \text{ feet}$$

$$A = \frac{Q}{C\,(2\,g\,h)^{1/2}} = \frac{0.86}{0.6[(2)(32.2)(0.48)]^{1/2}} = 0.13 \text{ ft}^2$$

$$D = \left(\frac{4A}{3.1416}\right)^{1/2} = 0.41 \text{ feet} = 5 \text{ inch orifice diameter}$$

Permanent Pool :

$$PPV_{rqd} = \frac{DA \times C \times R \times RT}{WS \times CF}$$

$$= \frac{(52)(0.78)(31)(14)}{(153)(12)}$$

$= 9.59$ acre-ft
$= 417,641\ ft^3$

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

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

$PPV_{provided} = 734,254\ ft^3$
$PPV_{provided} > PPV_{rqd}$ therefore the existing permanent pool is adequate

Littoral Zone:
The littoral zone for the treatment basin has already been established. Any disruption to the littoral zone will be restored to pre-construction conditions prior to project completion.

Pond Depth:
The depth of the pond will be excavated to a constant depth of 3 feet, which will comply with the maximum pond depth requirement of not less than 2 feet and not more than 8 feet.

Pond Configuration:
The length to width ratio is greater than the required 2:1. The discharge structure will be located out of close proximity of the inlet structures that the there is adequate mixing and short-circuiting is prevented.

Ground Water Table:
The groundwater table is located at approximately 75.20 feet. The 100 year flood elevation downstream of the discharge point is 75.0 feet.

Pond Side Slopes:
The existing pond side slopes are 4:1 (horizontal:vertical), which exceeds the minimum requirement of 3:1.

fl Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.20) [1]

Stanton 3
Pre-Development Analysis

```
********** Input Report ************************************************
--------Class: Node-----------------------------------------------------
   Name: DISCHARG   Base Flow(cfs): 0          Init Stage(ft): 75
  Group: BASE                                  Warn Stage(ft): 0
Comment:

Time(hrs)    Stage(ft)
0            75
48           75
--------Class: Node-----------------------------------------------------
   Name: SITE       Base Flow(cfs): 0          Init Stage(ft): 78.5
  Group: BASE                                  Warn Stage(ft): 0
Comment:

Stage(ft)    Area(ac)
73           5.6365
75           6.4688
77           7.3129
79           8.1687
80           8.601
--------Class: Operating Table------------------------------------------
   Name: WEIR          Type: Rating Curve
Comment:

   U/S Stage(ft)      Discharge(cfs)
   73                 0
   78.5               0
   79                 69.74
   80                 362.37

--------Class: Simulation-----------------------------------------------
C:\ICPR2\STANTON\STANTON
Execution: Both
   Header: Stanton 3
           Pre-Development Analysis
           Mean Annual Precipitation Event
---------HYDRAULICS-----------------------------HYDROLOGY--------------------
        Max Delta Z (ft): 1
          Delta Z Factor: 0.05          Override Defaults: No
     Time Step Optimizer: 10
Drop Structure Optimizer: 10
     Sim Start Time(hrs): 0
       Sim End Time(hrs): 48
      Min Calc Time(sec): 0.5
      Max Calc Time(sec): 60
        To Hour:   PInc(min):                    To Hour:   PInc(min):
        48         15                            48         15
---------GROUP SELECTIONS----------------------------------------------------
+ BASE     [01/11/01]
```

fl Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.20)
[1]

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Stanton 3
Pre-Development Analysis

********** Basin Summary - STANTON
****

***

Basin Name:	BLOCK
Group Name:	BASE
Node Name:	SITE
Hydrograph Type:	UH
Unit Hydrograph:	UH256
Peaking Factor:	256.00
Spec Time Inc (min):	8.00
Comp Time Inc (min):	8.00
Rainfall File:	SCSII-24
Rainfall Amount (in):	4.40
Storm Duration (hr):	24.00
Status:	ONSITE
Time of Conc. (min):	60.00
Lag Time (hr):	0.00
Area (acres):	61.00
Vol of Unit Hyd (in):	1.00
Curve Number:	84.90
DCIA (%):	14.75
Time Max (hrs):	12.53
Flow Max (cfs):	55.49
Runoff Volume (in):	3.03
Runoff Volume (cf):	670463

Stanton 3
Pre-Development Analysis
Mean Annual Precipitation Event

********** Link Maximum Conditions - STANTON **

(Time units - hours)

Link Name	Group Name	Max Time Flow	Max Flow (cfs)	Max Delta Q (cfs)	Max Time U/S Stage	Max US Stage (ft)	Max Time D/S Stage	Max DS Stage (ft)
SUMP	BASE	13.25	40.42	0.68	13.25	78.79	0.00	75.00

fl ..uvanced Interconnected Channel & Pond Routing (ICPR Ver 20) [1]

Stanton 3
Pre-Development Analysis
Mean Annual Precipitation Event

********** Node Maximum Conditions - STANTON **

(Time units - hours)

Node Name	Group Name	Max Time Conditions	Max Stage (ft)	Warning Stage (ft)	Max Delta Stage (ft)	Max Surface Area (sf)	Max Time Inflow	Max Inflow (cfs)	Max Time Outflow	Max Outflow (cfs)
DISCHARG	BASE	0.00	75.00	0.00	0.0000	0.00	13.25	40.42	0.00	0.00
SITE	BASE	13.25	78.79	0.00	0.0049	351910.41	12.50	54.99	13.25	40.42

fl Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.20) [1]

Stanton 3
Pre-Development Analysis

```
********** Input Report ****************************************************
--------Class: Node---------------------------------------------------------
   Name: DISCHARG   Base Flow(cfs): 0          Init Stage(ft): 75
  Group: BASE                                  Warn Stage(ft): 0
Comment:

Time(hrs)     Stage(ft)
0             75
48            75
--------Class: Node---------------------------------------------------------
   Name: SITE       Base Flow(cfs): 0          Init Stage(ft): 78.5
  Group: BASE                                  Warn Stage(ft): 0
Comment:

Stage(ft)     Area(ac)
73            5.6365
75            6.4688
77            7.3129
79            8.1687
80            8.601
--------Class: Operating Table----------------------------------------------
   Name: WEIR           Type: Rating Curve
Comment:

   U/S Stage(ft)      Discharge(cfs)
   73                 0
   78.5               0
   79                 69.74
   80                 362.37

--------Class: Simulation---------------------------------------------------
C:\ICPR2\STANTON\STANTON
Execution: Both
   Header: Stanton 3
           Pre-Development Analysis
           25 Year - 24 Hour Precipitation Event
---------HYDRAULICS-----------------------------HYDROLOGY-------------------
        Max Delta Z (ft): 1
          Delta Z Factor: 0.05          Override Defaults: No
     Time Step Optimizer: 10
Drop Structure Optimizer: 10
     Sim Start Time(hrs): 0
       Sim End Time(hrs): 48
      Min Calc Time(sec): 0.5
      Max Calc Time(sec): 60
        To Hour:   PInc(min):                 To Hour:   PInc(min):
        48         15                         48         15
---------GROUP SELECTIONS---------------------------------------------------
+ BASE     [01/11/01]
```

Stanton 3
Pre-Development Analysis
25 Year - 24 Hour Precipitation Event

********** Basin Summary - STANTON ***

***

Basin Name:	BLOCK
Group Name:	BASE
Node Name:	SITE
Hydrograph Type:	UH
Unit Hydrograph:	UH256
Peaking Factor:	256.00
Spec Time Inc (min):	8.00
Comp Time Inc (min):	8.00
Rainfall File:	SCSII-24
Rainfall Amount (in):	8.70
Storm Duration (hr):	24.00
Status:	ONSITE
Time of Conc. (min):	60.00
Lag Time (hr):	0.00
Area (acres):	61.00
Vol of Unit Hyd (in):	1.00
Curve Number:	84.90
DCIA (%):	14.75
Time Max (hrs):	12.53
Flow Max (cfs):	130.40
Runoff Volume (in):	7.13
Runoff Volume (cf):	1578746

Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.20) [1]

Stanton 3
Pre-Development Analysis
25 Year - 24 Hour Precipitation Event

********** Link Maximum Conditions - STANTON **

(Time units - hours)

Link Name	Group Name	Max Time Flow	Max Flow (cfs)	Max Delta Q (cfs)	Max Time U/S Stage	Max US Stage (ft)	Max Time D/S Stage	Max DS Stage (ft)
SUMP	BASE	13.03	105.02	2.81	13.03	79.12	0.00	75.00

Stanton 3
Pre-Development Analysis
25 Year - 24 Hour Precipitation Event

********** Node Maximum Conditions - STANTON **

(Time units - hours)

Node Name	Group Name	Max Time Conditions	Max Stage (ft)	Warning Stage (ft)	Max Delta Stage (ft)	Max Surface Area (sf)	Max Time Inflow	Max Inflow (cfs)	Max Time Outflow	Max Outflow (cfs)
DISCHARG	BASE	0.00	75.00	0.00	0.0000	0.00	13.03	105.02	0.00	0.00
SITE	BASE	13.03	79.12	0.00	0.0109	358098.59	12.50	129.49	13.03	105.02

fl Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.20) [1]

Stanton 3
Post-Development Analysis

********** Input Report **

--------Class: Node--

Name: DISCHARG   Base Flow(cfs): 0   Init Stage(ft): 75
Group: BASE   Warn Stage(ft): 0
Comment:

Time(hrs)	Stage(ft)
0	75
48	75

--------Class: Node--

Name: SITE   Base Flow(cfs): 0   Init Stage(ft): 78.5
Group: BASE   Warn Stage(ft): 0
Comment:

Stage(ft)	Area(ac)
73	5.6365
75	6.4688
77	7.3129
79	8.1687
80	8.601

--------Class: Operating Table---

Name: WEIR   Type: Rating Curve
Comment:

U/S Stage(ft)	Discharge(cfs)
75	0
75.5	0.36
76	0.59
76.5	0.75
77	14.3
77.5	26.09
78	33.96
78.5	40.31
79	45.78
79.5	50.66
80	55.1

--------Class: Simulation--

C:\ICPR2\STANTON\STANTON
Execution: Both
Header: Stanton 3
Post-Development Analysis
25 Year - 24 Hour Precipitation Event

---------HYDRAULICS----------------------------HYDROLOGY-------------------

Max Delta Z (ft): 1
Delta Z Factor: 0.05   Override Defaults: No
Time Step Optimizer: 10
Drop Structure Optimizer: 10
Sim Start Time(hrs): 0
Sim End Time(hrs): 48
Min Calc Time(sec): 0.5
Max Calc Time(sec): 60

To Hour:	PInc(min):	To Hour:	PInc(min):
48	15	48	15

---------GROUP SELECTIONS--

+ BASE   [01/11/01]

Stanton 3
Post-Development Analysis
25 Year - 24 Hour Precipitation Event

********** Basin Summary - STANTON **

***

Basin Name:	BLOCK
Group Name:	BASE
Node Name:	SITE
Hydrograph Type:	UH
Unit Hydrograph:	UH256
Peaking Factor:	256.00
Spec Time Inc (min):	8.00
Comp Time Inc (min):	8.00
Rainfall File:	SCSII-24
Rainfall Amount (in):	8.70
Storm Duration (hr):	24.00
Status:	ONSITE
Time of Conc. (min):	60.00
Lag Time (hr):	0.00
Area (acres):	61.00
Vol of Unit Hyd (in):	1.00
Curve Number:	90.70
DCIA (%):	14.75
Time Max (hrs):	12.53
Flow Max (cfs):	139.20
Runoff Volume (in):	7.73
Runoff Volume (cf):	1711179

Stanton 3
Post-Development Analysis
25 Year - 24 Hour Precipitation Event

********** Link Maximum Conditions - STANTON **

(Time units - hours)

Link Name	Group Name	Max Time Flow	Max Flow (cfs)	Max Delta Q (cfs)	Max Time U/S Stage	Max US Stage (ft)	Max Time D/S Stage	Max DS Stage (ft)
SUMP	BASE	15.15	42.59	40.31	15.15	78.71	0.00	75.00

Advanced Interconnected Channel & Pond Routing (ICPR Ver 2. [1]
Copyright 1995, Streamline Technologies, Inc.

Stanton 3
Post-Development Analysis
25 Year - 24 Hour Precipitation Event

********** Node Maximum Conditions - STANTON **

(Time units - hours)

Node Name	Group Name	Max Time Conditions	Max Stage (ft)	Warning Stage (ft)	Max Delta Stage (ft)	Max Surface Area (sf)	Max Time Inflow	Max Inflow (cfs)	Max Time Outflow	Max Outflow (cfs)
DISCHARG	BASE	0.00	75.00	0.00	0.0000	0.00	15.15	42.59	0.00	0.00
SITE	BASE	15.15	78.71	0.00	0.0203	350388.38	12.50	138.35	15.15	42.59

fl Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.20) [1]
Copyright 1995, Streamline Technologies, Inc.

Stanton 3
Pre-Development Analysis

```
********** Input Report ************************************************************
--------Class: Node-------------------------------------------------------------------
   Name: DISCHARG   Base Flow(cfs): 0          Init Stage(ft): 75
  Group: BASE                                  Warn Stage(ft): 0
Comment:

Time(hrs)     Stage(ft)
0             75
48            75
--------Class: Node-------------------------------------------------------------------
   Name: SITE       Base Flow(cfs): 0          Init Stage(ft): 78.5
  Group: BASE                                  Warn Stage(ft): 0
Comment:

Stage(ft)     Area(ac)
73            5.6365
75            6.4688
77            7.3129
79            8.1687
80            8.601
--------Class: Operating Table--------------------------------------------------------
   Name: WEIR          Type: Rating Curve
Comment:

   U/S Stage(ft)      Discharge(cfs)
   73                 0
   78.5               0
   79                 69.74
   80                 362.37

--------Class: Simulation-------------------------------------------------------------
C:\ICPR2\STANTON\STANTON
Execution: Both
   Header: Stanton 3
           Pre-Development Analysis
           100 Year - 24 Hour Precipitation Event
---------HYDRAULICS-----------------------------HYDROLOGY--------------------
        Max Delta Z (ft): 1
          Delta Z Factor: 0.05          Override Defaults: No
     Time Step Optimizer: 10
Drop Structure Optimizer: 10
     Sim Start Time(hrs): 0
       Sim End Time(hrs): 48
      Min Calc Time(sec): 0.5
      Max Calc Time(sec): 60
        To Hour:   PInc(min):                To Hour:   PInc(min):
        48         15                        48         15
---------GROUP SELECTIONS----------------------------------------------------
+ BASE     [01/11/01]
```

fl Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.20) [1]

Stanton 3
Pre-Development Analysis
100 Year - 24 Hour Precipitation Event

********** Basin Summary - STANTON ***

***

Basin Name:	BLOCK
Group Name:	BASE
Node Name:	SITE
Hydrograph Type:	UH
Unit Hydrograph:	UH256
Peaking Factor:	256.00
Spec Time Inc (min):	8.00
Comp Time Inc (min):	8.00
Rainfall File:	SCSII-24
Rainfall Amount (in):	10.80
Storm Duration (hr):	24.00
Status:	ONSITE
Time of Conc. (min):	60.00
Lag Time (hr):	0.00
Area (acres):	61.00
Vol of Unit Hyd (in):	1.00
Curve Number:	84.90
DCIA (%):	14.75
Time Max (hrs):	12.53
Flow Max (cfs):	167.05
Runoff Volume (in):	9.18
Runoff Volume (cf):	2033462

fl

Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.20) [1]

Stanton 3
Pre-Development Analysis
100 Year - 24 Hour Precipitation Event

********** Link Maximum Conditions - STANTON **

(Time units - hours)

Link Name	Group Name	Max Time Flow	Max Flow (cfs)	Max Delta Q (cfs)	Max Time U/S Stage	Max US Stage (ft)	Max Time D/S Stage	Max DS Stage (ft)
SUMP	BASE	12.98	138.76	3.88	12.98	79.24	0.00	75.00

f1 Advanced Interconnected Channel & Pond Routing (ICPR ... 2.20) [1]

Stanton 3
Pre-Development Analysis
100 Year - 24 Hour Precipitation Event

********** Node Maximum Conditions - STANTON **

(Time units - hours)

Node Name	Group Name	Max Time Conditions	Max Stage (ft)	Warning Stage (ft)	Max Delta Stage (ft)	Max Surface Area (sf)	Max Time Inflow	Max Inflow (cfs)	Max Time Outflow	Max Outflow (cfs)
DISCHARG	BASE	0.00	75.00	0.00	0.0000	0.00	12.98	138.76	0.00	0.00
SITE	BASE	12.98	79.24	0.00	0.0136	360270.26	12.50	165.95	12.98	138.76

fl Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.20) [1]

Stanton 3
Post-Development Analysis

********** Input Report **

--------Class: Node--

Name: DISCHARG Base Flow(cfs): 0 Init Stage(ft): 75
Group: BASE Warn Stage(ft): 0
Comment:

Time(hrs)	Stage(ft)
0	75
48	75

--------Class: Node--

Name: SITE Base Flow(cfs): 0 Init Stage(ft): 78.5
Group: BASE Warn Stage(ft): 0
Comment:

Stage(ft)	Area(ac)
73	5.6365
75	6.4688
77	7.3129
79	8.1687
80	8.601

--------Class: Operating Table---

Name: WEIR Type: Rating Curve
Comment:

U/S Stage(ft)	Discharge(cfs)
75	0
75.5	0.36
76	0.59
76.5	0.75
77	14.3
77.5	26.09
78	33.96
78.5	40.31
79	45.78
79.5	50.66
80	55.1

--------Class: Simulation--

C:\ICPR2\STANTON\STANTON
Execution: Both
Header: Stanton 3
Post-Development Analysis
100 Year - 24 Hour Precipitation Event

---------HYDRAULICS---------------------------HYDROLOGY-------------------

Max Delta Z (ft): 1
Delta Z Factor: 0.05 Override Defaults: No
Time Step Optimizer: 10
Drop Structure Optimizer: 10
Sim Start Time(hrs): 0
Sim End Time(hrs): 48
Min Calc Time(sec): 0.5
Max Calc Time(sec): 60

To Hour:	PInc(min):	To Hour:	PInc(min):
48	15	48	15

---------GROUP SELECTIONS--

+ BASE [01/11/01]

Advanced Interconnected Channel & Pond Routing (ICPR Ver 2.20)

Stanton 3
Post-Development Analysis
100 Year - 24 Hour Precipitation Event

*********** Basin Summary - STANTON **

***

Basin Name:	BLOCK
Group Name:	BASE
Node Name:	SITE
Hydrograph Type:	UH
Unit Hydrograph:	UH256
Peaking Factor:	256.00
Spec Time Inc (min):	8.00
Comp Time Inc (min):	8.00
Rainfall File:	SCSII-24
Rainfall Amount (in):	10.80
Storm Duration (hr):	24.00
Status:	ONSITE
Time of Conc. (min):	60.00
Lag Time (hr):	0.00
Area (acres):	61.00
Vol of Unit Hyd (in):	1.00
Curve Number:	90.70
DCIA (%):	14.75
Time Max (hrs):	12.53
Flow Max (cfs):	175.37
Runoff Volume (in):	9.81
Runoff Volume (cf):	2172260

Stanton 3
Post-Development Analysis
100 Year - 24 Hour Precipitation Event

********** Link Maximum Conditions - STANTON **********

(Time units - hours)

Link Name	Group Name	Max Time Flow	Max Flow (cfs)	Max Delta Q (cfs)	Max Time U/S Stage	Max US Stage (ft)	Max Time D/S Stage	Max DS Stage (ft)
SUMP	BASE	15.35	49.38	40.31	15.35	79.37	0.00	75.00

Stanton 3
Post-Development Analysis
100 Year - 24 Hour Precipitation Event

********** Node Maximum Conditions - STANTON **********

(Time units - hours)

Node Name	Group Name	Max Time Conditions	Max Stage (ft)	Warning Stage (ft)	Max Delta Stage (ft)	Max Surface Area (sf)	Max Time Inflow	Max Inflow (cfs)	Max Time Outflow	Max Outflow (cfs)
DISCHARG	BASE	0.00	75.00	0.00	0.0000	0.00	15.35	49.38	0.00	0.00
SITE	BASE	15.35	79.37	0.00	0.0257	362783.83	12.50	174.34	15.35	49.38

STANTON

flow based on weir equation

Q=cLh^1.5

where: c= 3

L= 10

h= head in feet

weir elev.= 76.8

flow based on orifice

Q=cA(2gh)^0.5

where: c= 0.6

A= 0.14

h= head in feet

g= 32.2 ft/sec^2

orifice in inches= 5

in feet = 0.42

orifice elev.= 75.2

stage	h (ft)	Q(cfs)	stage	h(ft)	Q(cfs)	TOTAL Q cfs
80	3.2	53.67	80	4.8	1.44	55.10
79.5	2.7	49.30	79.5	4.3	1.36	50.66
79	2.2	44.50	79	3.8	1.28	45.78
78.5	1.7	39.12	78.5	3.3	1.19	40.31
78	1.2	32.86	78	2.8	1.10	33.96
77.5	0.7	25.10	77.5	2.3	1.00	26.09
77	0.2	13.42	77	1.8	0.88	14.30
76.5	0	0.00	76.5	1.3	0.75	0.75
76	0	0.00	76	0.8	0.59	0.59
75.5	0	0.00	75.5	0.3	0.36	0.36
75	0	0.00	75	0	0.00	0.00
74.5	0	0.00	74.5	0	0.00	0.00
74	0	0.00	74	0	0.00	0.00

Attachment SJRWMD-1

ORANGE COUNTY GOVERNMENT FLORIDA

UTILITIES DEPARTMENT
MICHAEL L. CHANDLER, *Director*
9150 Curry Ford Road
Orlando, Florida 32825
Telephone: 407-254-9804
Fax: 407-254-9899
Email: michael.chandler@ocfl.net

October 24, 2004

Ken Ksionek
General Manager and CEO
Orlando Utilities Commission
500 S. Orange Avenue
Orlando, Florida 32802

Certified Mail # 7002 3150 0000 6063 8371

Frederick F. Haddad
Vice-President, Power Resources
Orlando Utilities Commission
500 S. Orange Avenue
Orlando, Florida 32802

Certified Mail # 7002 3150 0000 6063 6388

Dear Mr. Ksionek and Mr. Haddad:

This letter is sent in response to Mr. Haddad's letter requesting written confirmation by November 1, 2005, of the availability of and willingness to provide supply water for use as cooling water at Stanton Energy Center (SEC) Unit 4.

Please accept this letter as written notice pursuant to Section 3.1.4 of the First Amendment to and Restatement of the Substitute agreement between Orange County and OUC relating to Cooling Water Supply that Orange County commits to providing 3.5 mgd of supply water on an annual average basis to SEC Unit 4 beginning June 1, 2010 as well as 5.0 mgd of supply water on an annual average basis for phase two of SEC Unit 4 by June 1, 2014.

In recent discussions between Orange County and OUC staff, it has been suggested that these volumes may be peak conditions instead of annual average and that the method of supply water delivery for Unit 4 may be different than the current method. We look forward to continuing these discussions with your staff.

Sincerely,

MLChandler

Michael L. Chandler

c: Teresa Remudo-Fries, P. E., Deputy Director, Orange County Utilities
Daniel L. Allen, P. E., Deputy Director, Orange County Utilities
Ray Hanson, P. E., Manager, Water Reclamation Division, Orange County Utilities
Anthony Cotter, Assistant County Attorney

S:\ACotter\CORRES\OUC Cooling water Unit 4 tr 10-24-05.doc

Attachment FDEP E-MAIL-1

General ~~Test~~ Laboratory
P.O. Box 2641
Birmingham, Alabama 35291
(205) 664 - 6081

ALABAMA POWER
A SOUTHERN COMPANY

CERTIFICATE OF ANALYSIS

To: Ms. Wynema Kimbrough
PSDF P.O. Box 1069
Wilsonville, AL 35186

Customer Account : HWPSDF
Sample Date : 25-Nov-02
Customer ID : PSDF
Delivery Date : 09-Dec-02

Description: PSDF - S# AB11871
KASHSILO SIO814 Run# TC10 (COAL ASH)

Laboratory ID Number: AG38341

Name	Analyst	Test Date	Reference	Vio Spec	MDL	Results	Units
Volatile Compounds							
Benzene (TCLP)	RAH	12/16/02	EPA1311/8260		.005	Not Detected	mg/l
Carbon Tetrachloride (TCLP)	RAH	12/16/02	EPA1311/8260		.005	Not Detected	mg/l
Chlorobenzene (TCLP)	RAH	12/16/02	EPA1311/8260		.005	Not Detected	mg/l
1,4-Dichlorobenzene (TCLP)	RAH	12/16/02	EPA1311/8260		.005	Not Detected	mg/l
1,2-Dichloroethane (TCLP)	RAH	12/16/02	EPA1311/8260		.005	Not Detected	mg/l
1,1-Dichloroethene (TCLP)	RAH	12/16/02	EPA1311/8260		.005	Not Detected	mg/l
Methyl Ethyl Ketone (TCLP)	RAH	12/16/02	EPA1311/8260		.005	Not Detected	mg/l
Tetrachloroethene (TCLP)	RAH	12/16/02	EPA1311/8260		.005	Not Detected	mg/l
Trichloroethene (TCLP)	RAH	12/16/02	EPA1311/8260		.005	Not Detected	mg/l
Vinyl Chloride (TCLP)	RAH	12/16/02	EPA 8260		.005	Not Detected	mg/l
Metals, Cyanide, Total Phenols							
Arsenic, TCLP Extractable	JA3	12/13/02	EPA1311/6010		0.009	0.030	mg/l
Barium, TCLP Extractable	JA3	12/13/02	EPA1311/6010		0.003	0.596	mg/l
Chromium, TCLP Extractable	JA3	12/13/02	EPA1311/6010		0.01	0.07	mg/l
Cadmium, TCLP Extractable	JA3	12/13/02	EPA1311/6010		0.001	0.014	mg/l
Lead, TCLP Extractable	JA3	12/13/02	EPA1311/6010		0.01	Not Detected	mg/l
Mercury, TCLP Extractable	RDA	12/16/02	EPA1311/7470		0.0002	Not Detected	mg/l
Silver, TCLP Extractable	JA3	12/13/02	EPA1311/6010		0.006	Not Detected	mg/l
Selenium, TCLP Extractable	JA3	12/13/02	EPA1311/6010		0.02	Not Detected	mg/l
General Characteristics							
Solids Content of Sample	WH	12/10/02	EPA 1311		0.01	100	per cent
pH of TCLP Extract	WH	12/13/02	EPA 1311		0.	5.19	
Extraction Fluid #	WH	12/10/02	EPA 1311		0.	2	
Base/Neutral Compounds							
2,4-Dinitrotoluene (TCLP)	RAH	12/18/02	EPA1311/8270		0.003	Not Detected	mg/l
Hexachlorobenzene (TCLP)	RAH	12/18/02	EPA1311/8270		0.003	Not Detected	mg/l
Hexachlorobutadiene (TCLP)	RAH	12/18/02	EPA1311/8270		0.008	Not Detected	mg/l
Hexachloroethane (TCLP)	RAH	12/18/02	EPA1311/8270		0.007	Not Detected	mg/l

This Certificate is for the physical and/or chemical characteristics of the sample as submitted.

Comments:

cc: Mr. Charles Cantrell
Mr. Tommy Ryals

Quality Control ______________ **Supervision** ______________ **Date:** 06-Jan-03

smk/NC

BEST AVAILABLE COPY

[illegible] Laboratory
[illegible]2641
[illegible]nam, Alabama 35291
[illegible]664 - 6081

ALABAMA POWER
A SOUTHERN COMPANY

CERTIFICATE OF ANALYSIS

[illegible]: Ms. Wynema Kimbrough
PSDF P.O. Box 1069
Wilsonville, AL 35186

Customer Account : HWPSDF
Sample Date : 25-Nov-02
Customer ID : PSDF
Delivery Date : 09-Dec-02

Description: PSDF - S# AB11871
KASHSILO SIO814 Run# TC10

Laboratory ID Number: AG38341

Name	Analyst	Test Date	Reference	Vio Spec	MDL	Results	Units
Base/Neutral Compounds							
Nitrobenzene (TCLP)	RAH	12/18/02	EPA1311/8270		0.005	Not Detected	mg/l
Acid Compounds							
2-Methylphenol (TCLP)	RAH	12/18/02	EPA1311/8270		0.004	Not Detected	mg/l
3&4-Methylphenol (TCLP)	RAH	12/18/02	EPA1311/8270		0.002	Not Detected	mg/l
Pentachlorophenol (TCLP)	RAH	12/18/02	EPA1311/8270		0.002	Not Detected	mg/l
Pyridine (TCLP)	RAH	12/18/02	EPA1311/8270		0.004	Not Detected	mg/l
2,4,5-Trichlorophenol (TCLP)	RAH	12/18/02	EPA1311/8270		0.005	Not Detected	mg/l
2,4,6-Trichlorophenol (TCLP)	RAH	12/18/02	EPA1311/8270		0.005	Not Detected	mg/l
Miscellaneous							
Method 8270 - Extraction Date	RAH	12/13/02				12/13/02	
Sulfide, Total Releasable as H2S	FKK	12/10/02	SW846/S.7.3		0.4	51.6	mg/kg
Sulfide,Specific Rate of Release	FKK	12/10/02	SW846/S.7.3		0.002	0.029	mg/kg/s

This Certificate is for the physical and/or chemical characteristics of the sample as submitted.

Comments:

cc: Mr. Charles Cantrell
Mr. Tommy Ryals

Quality Control [signature] **Supervision** [signature] **Date:** 06-Jan-03

smk/NC

TCLP Test Results for Transport Gasifier Ash (ppm)

	Run	Date	Arsenic	Barium	Cadmium	Chromium	Mercury	Lead	Selenium	Silver
	TC14	2/28/2004	ND	11.2	0.001	ND	ND	ND	ND	ND
	TC14	2/25/2004	ND	10.6	ND	ND	ND	ND	ND	ND
	TC13	11/1/2003	ND	4.49	ND	ND	ND	ND	ND	ND
	TC10	11/25/2002	0.030	0.596	0.014	0.070	ND	ND	ND	ND
	TC06	7/19/2001	ND	67.200	ND	ND	ND	0.050	ND	ND
	GCT4	6/12/2001	ND	0.983	ND	0.002	ND	ND	ND	ND
	GCT3	2/7/2001	ND	18.400	ND	0.010	ND	ND	ND	ND
	GCT3	2/5/2001	ND	3.390	ND	ND	ND	ND	ND	ND
	GCT2	10/27/2000	0.202	0.167	ND	0.110	ND	ND	ND	ND
	GCT2	4/28/2000	0.005	2.460	ND	0.034	ND	ND	0.029	0.002
Average			0.079	11.949	0.008	0.045	---	0.050	0.029	0.002
Reg Limit			5.000	100.000	1.000	5.000	0.200	5.000	1.000	5.000

ND=Not Detected

HEADWATERS RESOURCES

Adding Value to Energy™

ASTM C618-03 / AASHTO M 295-00 Testing of Orlando Utility Coal Gasification Fly Ash

Type of sample:		**Report Date:**	February 2, 2006
Date of sample:	Received 12/30/05	**MTRF I.D.**	2312TS

Chemical Analysis		ASTM / AASHTO Limits Class F	ASTM / AASHTO Limits Class C	ASTM Test Method
Silicon Dioxide (SiO_2)	46.75 %			
Aluminum Oxide (Al_2O_3)	17.01 %			
Iron Oxide (Fe_2O_3)	5.11 %			
Sum of Constituents	68.87 %	70.0% min	50.0% min	D4326
Sulfur Trioxide (SO_3)	0.76 %	5.0% max	5.0 % max	D4326
Calcium Oxide (CaO)	19.69 %			D4326
Moisture Content	0.44 %	3.0% max	3.0% max	C311
Loss on Ignition	39.80 %	6.0% max	6.0% max	C311
(AASHTO M 295-00 req.)		5.0% max	5.0% max	
Available Alkalies, as Na_2O **	0.23 %			C311
(AASHTO M 295-00 req.)		1.5% max	1.5% max	
Physical Analysis				
Fineness, % retained on #325	11.21 %	34% max	34% max	C311, C430
Strength Activity Index – 7 or 28 day requirement				C311, C109
7 day, % of control	73 %	75% min	75% min	
28 day, % of control	93 %	75% min	75% min	
Water Requirement, % control	121 %	105% max	105% max	
Autoclave Soundness	-0.01 %	0.8% max	0.8% max	C311, C151
True Particle Density	2.14			

** *Supplementary Optional Chemical Requirement (Available Alkali) was removed by ASTM C618-01*

Headwaters Resources certifies that, to the best of its knowledge, the test data listed herein was generated by applicable ASTM methods and does not meet the requirements of ASTM C618-05.

Bobby Bergman

Bobby Bergman
MTRF Manager

AAP℠ AASHTO R18

Materials Testing & Research Facility
2650 Highway 113 S.W.
Taylorsville, Georgia 30178
P: 770.684.0102
F: 770.684.5114
www.headwaters.com