

Appendix 10.2

Federal Permit Applications or Approvals

Appendix 10.2.1

316(b) Demonstrations

10.2.1 316(b) Demonstrations

Seminole Generating Station (SGS) holds a National Pollutant Discharge Elimination System (NPDES) permit (FL0036498), originally issued for Units 1 and 2 in November 15, 1979. The cooling water intake for Units 1 and 2 are subject to Clean Water Act (CWA) Section 316(b), since it withdraws cooling tower makeup from the St. Johns River. SGS maintains a thermal mixing zone in the permit under Rule 62-302.520(6), Florida Administrative Code (F.A.C.), which satisfies Florida's water quality standards without the need for a thermal variance under Section 316(a) of the CWA.

The earliest studies on the effects of SGS on the St. Johns River under CWA 316(b) were conducted by Seminole Electric Cooperative, Inc. (SECI), as part of the site certification application process for Units 1 and 2 in 1979.¹ These studies consisted of extensive testing and analyses of impingement and entrainment of susceptible fish and macroinvertebrates using a test intake apparatus operated in the St. Johns River at the proposed intake site. The study design was approved by the U.S. Environmental Protection Agency, U.S. Fish & Wildlife Service, Florida Department of Environmental Regulation (now the Florida Department of Environmental Protection [FDEP]), and the Florida Game and Freshwater Fish Commission (now the Florida Fish and Wildlife Conservation Commission) as a plan of study to determine best technology available (BTA).

The study involved the identification of potentially entrainable species present in the intake location area, estimation of mitigation of potential fish and macroinvertebrate losses caused by intake operation, analysis of the impingement and entrainment of two slot sizes on bulkhead-mounted cylindrical wedgewire screens, assessment of proper distance from shore to locate the proposed intake and discharge with consideration of potential spawning or nursery habitats, areas of high fish concentration and high productivity, and the operating feasibly (i.e., reliability) and biofouling potential of the intake screens. Through this study it was determined SGS Units 1 and 2 would meet Section 316(b) criteria for BTA for minimizing environmental impact.

The 316(b) rule has undergone a number of revisions since the original NPDES issuance. SGS remains subject to the final 316(b) rule for existing facilities, which regulates the location, design, construction, and

¹ Dames & Moore. 1979. Seminole Plant Units No. 1 and No. 2 316B Study and Report.

operation of cooling water intake structures (CWIS) at existing facilities that hold an NPDES permit, withdraw more than 2 million gallons per day from Waters of the United States, and use at least 25 percent of that water exclusively for cooling purposes. The final rule supersedes the Phase II rule, which was remanded in 2007, and the remanded existing facility portion of the previously promulgated Phase III rule. The final 316(b) rule became effective on October 14, 2014.

The original 316(b) studies described herein are the only demonstrations that have been required to date and have supported prior determinations that the CWIS constitutes BTA under 316(b). No major modifications to the intake structure have been completed; therefore, no additional studies under 316(b) have been required.

The final 316(b) rule requires each affected facility develop and submit to the NPDES director (i.e., FDEP) specific submittals and supporting information to address compliance with the rule's BTA requirements. Submittal of 316(b) rule-related reports for existing facilities is generally coordinated with the facility's application to renew its NPDES permit. SGS's NPDES permit (FL0036498) has been administratively continued while the renewal process is ongoing. The renewal application including the 316(b) rule-related reports was submitted to FDEP in February 2017, and is currently under review by FDEP.

Appendix 10.2.2

NPDES Application/Permits

10.2.2 NPDES Application/Permits

The Seminole Generating Station (SGS) is currently authorized to operate under a National Pollutant Discharge Elimination System (NPDES) permit, No. FL0036498, issued for Units 1 and 2 (see Appendix 10.6.2). A permit renewal application was submitted to the Florida Department of Environmental Protection (FDEP) on February 28, 2017, and is currently under review. The existing NPDES permit has been administratively continued while the renewal process is ongoing.

For the Seminole Combined-Cycle Facility (SCCF or Project), Seminole Electric Cooperative, Inc. (SECI), will submit a revision of the NPDES industrial wastewater facility permit No. FL0036498 (following issuance of the renewed permit anticipated in early 2018) to include SCCF and associated changes in the facility water balance and wastewater discharge plans. Coincident with the declared commercial operation of SCCF, SECI intends to permanently remove from service one of the two Existing SGS Units. Therefore, the information in the attached NPDES revision reflects the SGS operations with the one Remaining SGS Unit² and the proposed SCCF.

The industrial wastewater facility or activity permit application (FDEP Forms 1 and 2CS) and supporting information for the permit revision to be requested are provided in this appendix. The permit application will be submitted separately to the FDEP Industrial Wastewater Section, Power Plant NPDES Permitting, following issuance of the renewed permit.

² Remaining SGS Unit as used throughout this document is intended to refer to the Existing SGS Unit that will continue to be operated beyond achieving commercial operation of the proposed SCCF. A decision as to which of the two Existing SGS Units will be removed from service will be made in the future.



WASTEWATER FACILITY OR ACTIVITY PERMIT APPLICATION FORM 1 GENERAL INFORMATION

This form must be completed by all persons applying for a permit for a wastewater facility or activity under Chapter 62-620, F.A.C. See Form 1 to determine which other application forms you will need.



WASTEWATER FACILITY OR ACTIVITY PERMIT APPLICATION FORM 1 GENERAL INFORMATION

I IDENTIFICATION NUMBER:

Facility ID FL0036498

II CHARACTERISTICS:

INSTRUCTIONS: Complete the questions below to determine whether you need to submit any permit application forms to the Department of Environmental Protection. If you answer "yes" to any questions, you must submit this form and the supplemental form listed in the parenthesis following the question. Mark "X" in the blank in the third column if the supplemental form is attached. If you answer "no" to each question, you need not submit any of these forms. You may answer "no" if your activity is excluded from permit requirements. See Section B of the instructions. See also, Section C of the instructions for definitions of the terms used here.

SPECIFIC QUESTIONS	YES	NO	FORM ATTACHED
A. Is this facility a domestic wastewater facility which results in a discharge to surface or ground waters?		X	
B. Does or will this facility (either existing or proposed) include a concentrated animal feeding operation or aquatic animal production facility which results in a discharge to waters?		X	
C. Does or will this facility (other than those describe in A. or B.) discharge process wastewater, or non-process wastewater regulated by effluent guidelines or new source performance standards, to surface waters?	X		2CS
D. Does or will this facility (other than those described in A. or B.) discharge process wastewater to ground waters?	X		
E. Does or will this facility discharge non-process wastewater, not regulated by effluent guidelines or new source performance standards, to surface waters?		X	
F. Does or will this facility discharge non-process wastewater to ground waters?		X	
G. Does or will this facility discharge stormwater associated with industrial activity to surface waters?	X		
H. Is this facility a non-discharging/closed loop recycle system?		X	
I. Is this facility a public water system whose primary purpose is the production of potable water for public consumption and which discharges demineralization concentrate to surface water or groundwater?		X	

III NAME OF FACILITY: (40 characters and spaces)

Seminole Generating Station

IV FACILITY CONTACT: (A. 30 characters and spaces)

A. Name and Title (Last, first, & title)	B. Phone (area code & no.)
Gostnell, Justin, Sr. Environmental Coordinator	(813) 739-1375

V FACILITY MAILING ADDRESS: (A. 30 characters and spaces; B. 25 characters and spaces)

A. Street or P.O. Box: 16313 North Dale Mabry Highway		
B. City or Town: Tampa	State: FL	Zip Code: 33618

VI FACILITY LOCATION: (A. 30 characters and spaces; B. 24 characters and spaces; C. 3 spaces (if known); D. 25 characters and spaces; E. 2 spaces; F. 9 spaces)

A. Street, Route or Other Specific Identifier: 890 Highway 17 North		
B. County Name: Putnam	C. County Code (if known):	
D. City or Town: Palatka	E. State: FL	F. Zip Code: 32177

VII SIC CODES: (4-digit, in order of priority)

1. Code #: 4911	(Specify) Electric Services	2. Code #:	(Specify)
3. Code #:	(Specify)	4. Code #:	(Specify)

VIII OPERATOR INFORMATION: (A. 40 characters and spaces; B. 1 character; C. 1 character (if other, specify); D. 12 characters; E. 30 characters and spaces; F. 25 characters and spaces; G. 2 characters; H. 9 characters)

A. Name: Seminole Electric Cooperative, Inc.		B. Is the name in VIII A. the owner? ☒ Yes ☐ No	
C. Status of Operator: F = Federal; S = State; P = Private; O = Other; M = Public (other than F or S)	(code) P	(specify) Private	D. Phone No.: (813) 963-0944
E. Street or P. O. Box: 16313 North Dale Mabry Highway			
F. City or Town: Tampa		G. State: FL	H. Zip Code: 33618

IX INDIAN LAND: Is the facility located on Indian lands?☐ Yes☒ No

X EXISTING ENVIRONMENTAL PERMITS:

A. NPDES Permit No.	B. UIC Permit No.	C. Other (specify)	D. Other (specify)
FL0036498		SCA COC PA 78-10M	

XI MAP: Attach to this application a topographic map of the area extending to at least one mile beyond property boundaries. The map must show the outline of the facility, the location of each of its existing and proposed intake and discharge structures, each of its hazardous waste treatment, storage, or disposal facilities, and each well where it injects fluids underground. Include all springs, rivers and other surface water bodies in the map area. See instructions for precise requirements. **See Form 2CS, Attachment 1 and Figures 1 and 2.**

XII NATURE OF BUSINESS (provide a brief description)

Seminole Generating Station is an electrical power generation plant that currently has two coal-fired, steam electric generating units. This revision is to add the Seminole Combined-Cycle Facility (SCCF) Project to the existing National Pollutant Discharge Elimination System (NPDES) Permit No. FL0036498. SCCF is a natural gas-fired, combined-cycle generating unit. This revision also reflects the removal from service of one of the coal-fired generating units.

XIII CERTIFICATION (see instructions)

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those persons immediately responsible for obtaining the information contained in the application, I believe that the information is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

James R. Frauen

A. Name (type or print)



B. Signature

Vice President, Power Delivery
and Technical Services

Official Title (type or print)

12-7-17

C. Date Signed



WASTEWATER APPLICATION FORM 2CS

PERMIT TO DISCHARGE PROCESS WASTEWATER
FROM NEW OR EXISTING
INDUSTRIAL WASTEWATER FACILITIES
TO SURFACE WATER

FORM 2CS



WASTEWATER APPLICATION FOR PERMIT TO DISCHARGE PROCESS WASTEWATER FROM NEW OR EXISTING INDUSTRIAL WASTEWATER FACILITIES TO SURFACE WATERS

Facility I.D. Number: **FL0036498**

Please print or type information in the appropriate areas.

I OUTFALL LOCATION For each outfall, list the X,Y coordinates and the name of the receiving water.
(latitude/longitude to the nearest 15 seconds)

A. Outfall No. (List)	B. Latitude			C. Longitude			D. Name of Receiving Water
	Deg.	Min.	Sec.	Deg.	Min.	Sec.	
D-001	29	42	41	81	38	14	St. Johns River

II OUTFALL DESIGN

A. Outfall No. (List)	B. Design Configuration and Construction Materials	C. Distance from shore	D. Diameter	E. Elevation of Discharge Invert (MSL)	F. Receiving Water Depth at POD (MSL)
D-001	16-inch diffuser with fifteen 6-inch risers oriented at 20 degrees above horizontal	900 ft	16 inches	-8 ft msl	10 ft

III RECEIVING WATER INFORMATION

For each surface water that will receive effluent, supply the following information:

A. Name of Receiving Water	B. Check One		C. Classification (See Ch. 62-302, F.A.C.)	D. Type of Receiving Water (canal, river, lake, etc.)
	Fresh	Salt or Brackish		
St. Johns River	☒	☐	Class III	River
	☐	☐		
	☐	☐		
	☐	☐		
	☐	☐		
	☐	☐		

E. Minimum 7-day 10-year low flow of the receiving water at each outfall (if appropriate).

St. Johns River near Palatka is a tidally influenced stream. 7Q10 is not applicable.

F. Identify and describe the flow of effluent from each outfall to a major body of water. A suitably marked map or aerial photograph may be used.

Cooling tower makeup water will be withdrawn from the St. Johns River through the existing SGS intake structure, and cooling tower blowdown, along with low-volume treated wastewaters, will be discharged to the river via the existing SGS discharge structure, D-001. The location of Outfall D-001 is shown in Attachments 1 and Figures 1 and 2.

G. Do you request a mixing zone under Rule 62-4.244, F.A.C.? If yes, for what parameters or pollutants?

SECI is requesting a mixing zone for copper, cyanide, iron, mercury, selenium, specific conductance, temperature, and temperature rise.

IV FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B.

B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfalls. If a water balance cannot be determined (e.g., for certain mining activities), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

See Attachment 1, Figure 3, for existing operation water balance and Figure 4 for proposed new SCCF Project water balance and supporting narrative.

B. For each outfall, provide a description of:

1. All operations contributing wastewater to the effluent; including process wastewater, sanitary wastewater, cooling water, and stormwater runoff;
2. The average flow contributed by each operation; and
3. The treatment received by the wastewater.

Use the space on the next page. Continue on additional sheets, if necessary.

(1) Outfall No. (List)	(2) Operation(s) Contributing Flow		(3) Treatment		
	(a) Operation (list)	(b) Avg. Flow & Units	(a) Description	(b) List Code from Table 2CS-1	
D-001	Internal Outfalls I-002, I-003, I-04A or I-04B, I-006 and proposed I-007 from the Remaining Unit combined with the proposed combined-cycle plant	5.72 MGD	Discharge to surface waters		
I-002	Low-volume wastewater	1.123 MGD	Wastewater collected, settled	1-O, 1-U	
	Treated gypsum purge stream		Neutralized	2-K	
	Landfill drain water		Coagulated	2-D	
			Flocculated	1-G	
I-003	Sanitary wastewater	0.004 MGD	Screening	1-T	
			Activated sludge	3-A	
			Extended aeration	2-F	
I-04A	Unit 1 cooling tower blowdown	2.589 MGD	Disinfection	2-F	
I-04B	Unit 2 cooling tower blowdown	2.589 MGD	Disinfection	2-F	
I-006	Gypsum purge stream	0.505 MD	Chemical precipitation	2-C	
	combined with FGD landfill		Rapid sand filtration	1-R	
	Drain water		Coagulation	2-D	
			Reduction	2-L	
I-007 (proposed for Remaining Unit)	FGD Landfill Drain Water	0.245	Sedimentation	1-U	
			Filtration	1-V	
I-008 (proposed for Combined- Cycle)	Cooling tower blowdown	1.776	Disinfection	2-F	
I-009 (proposed for combined- cycle)	Sanitary wastewater	0.002 MGD	Screening	1-T	
			Activated sludge	3-A	
			Extended aeration	2-F	

C. Except for storm runoff, leaks, or spills, are any of the discharges described in Items II-A or B intermittent or seasonal?								
☐ Yes (complete the following table) ☒ No (go to D. below)								
(1) Outfall No. (List)	(2) Operation(s) Contributing Flow(List)	(3) Frequency		(4) Flow				
		(a) Days per Week	(b) Months per Yr.	(a) Flow Rate (in mgd)		(b) Total Volume (specify with units)		(c) Duration (in days)
		(specify avg.)	(specify avg.)	Long Term Avg.	Max. Daily	Long Term Avg.	Max. Daily	

D. Describe practices to be followed to ensure adequate wastewater treatment during emergencies such as power loss and equipment failures causing shutdown of pollution abatement equipment of the proposed/permitted facilities.

Power generating facilities are interconnected to the electrical grid and, therefore, have a reliable backup power supply. However, in the unlikely event of complete power loss, the cooling tower circulating water pump would cease to operate, and the valve at D-001 would be closed manually to prevent discharge.

E. List the method(s) and location(s) of flow measurement. **See Table 2 in Attachment 1 and Table A.**

V PRODUCTION

A. Does an effluent guideline limitation promulgated by EPA under Section 304 of the Clean Water Act apply to your facility?

☒ Yes (complete Item V-B) ☐ No (go to Section VI)

B. Are the limitations in the applicable guideline expressed in terms of production (or other measure of operation)?

☐ Yes (complete Item V-C) ☒ No (go to Section VI)

C. If you answered "yes" to Item V-B, list the quantity which represents an actual measurement of your level of production, expressed in the terms and units used in the applicable effluent guideline, and indicate the affected outfalls.

1. AVERAGE DAILY PRODUCTION			2. Affected Outfalls (list outfall nos.)
a. Quantity per Day	b. Units of Measure	c. Operation, Product, Materials, Etc. (specify)	
Not applicable.			

VI IMPROVEMENTS

A. Are you now required by any Federal, State or local authority to meet any implementation schedule for the construction, upgrading or operation of wastewater treatment equipment or practices or any other environmental programs which may affect the discharges described in this application? This includes, but is not limited to, permit conditions, administrative or enforcement order, enforcement compliance schedule letter, stipulations, court orders, and grant or loan conditions.

☒ Yes (complete the following table) ☐ No (go to Item VI-B)

1. Identification of Condition, Agreement, Etc.	2. Affected Outfalls		3. Brief Description of Project	4. Final Compliance Date	
	a. No.	b. Source of Discharge		a. Required	B. Projected
Consent Order OGC No. 12-0669	D-001	Combined plant waste streams	Installation of sulfite analyzers in FGD modules; installation of low shear mixers in FGD purge water treatment reactors	May 2018	April 2018
Effluent limitation guidelines	I-006	FGD purge water	See ELG compliance plan submitted with the permit renewal application in February 2017	Varied	Varied

B. OPTIONAL: You may attach additional sheets describing any additional water pollution control programs (or other environmental projects which may affect your discharges) you now have underway or which you plan. Indicate whether each program is now underway or planned, and indicate your actual or planned schedules for construction.

☐ Mark "X" if description of additional control programs is attached.

VII INTAKE AND EFFLUENT CHARACTERISTICS

A, B, & C: See instructions before proceeding--Complete one set of tables for each outfall -- Annotate the outfall number in the space provided. NOTE: Tables VII-A, VII-B, and VII-C are included on separate sheets number VII-1 through VII-9. **See Attachment 2 for antidegradation demonstration and attached mixing zone assessment.**

D. Use the space below to list any of the pollutants listed in Table 2CS-3 of the instructions, which you know or have reason to believe is discharged or may be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it to be present and report any analytical data in your possession.

1. Pollutant	2. Source	1. Pollutant	2. Source
Refer to 2CS data			

VIII POTENTIAL DISCHARGES NOT COVERED BY ANALYSIS

Is any pollutant listed in Item VII-C a substance or a component of a substance which you currently use or manufacture as an intermediate or final product or by-product?

☐ YES (list all such pollutants below) ☒ NO (go to IX)

IX BIOLOGICAL TOXICITY TESTING DATA

Do you have any knowledge or reason to believe that any biological test for acute or chronic toxicity has been made on any of your discharges or on a receiving water in relation to your discharge within the last 3 years?

☒ YES (identify the test(s) and describe their purposes below) ☐ NO (go to Section X)

Whole effluent tests have been conducted for Outfall D-001 discharge in the past several years to determine the LC50 96-hour acute toxicity.

X CONTRACT ANALYSIS INFORMATION

Were any of the analyses reported in Item VII performed by a contract laboratory or consulting firm?

☒ YES (list the name, address, telephone number, and certification number of, and pollutants analyzed by each such laboratory or firm below) ☐ NO (go to Section XI)

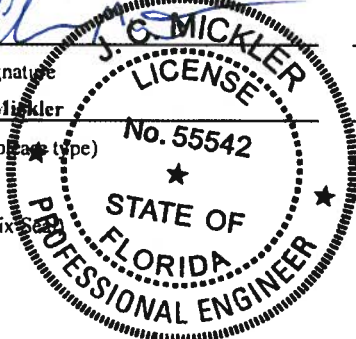
A. Name	B. Address	C. Telephone (area code & no.)	D. Pollutants Analyzed (list)
ALS Group USA, Corp F101294	9143 Phillips Highway Suite 200 Jacksonville, FL 32174	(904) 394-4410	All parameters except radioactive testing
Florida Radiochemistry Services, Inc. E83033	545 Hoffner Avenue, No. 201 Orlando, FL 32812	(407) 382-7733	Gross alpha, radium, gross beta

XI CONNECTION TO REGIONAL POTW

A. Indicate the relationship between this project and area regional planning for wastewater treatment. List steps to be taken for this industrial wastewater facility to become part of an area-wide wastewater treatment system.

XII-A CERTIFICATIONS FOR NEW OR MODIFIED FACILITIES

This is to certify the engineering features of this pollution control project have been designed by me and found to be in conformity with sound engineering principles, applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules of the Department. It is also agreed that the undersigned, if authorized by the owner, will furnish the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

	Signature <u>J. C. Mickler</u> J. Chris Mickler Name (please type) <u>★</u> (Affix Seal)	<u>Environmental Consulting & Technology, Inc.</u> Company Name Address <u>3701 Northwest 98th Street</u> <u>Gainesville, Florida 32606</u> Florida Registration No.: <u>55542</u> Telephone No.: <u>(352) 332-0444</u> Date <u>12-7-17</u>

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

<u>James. R. Frauen</u> <u>Vice President, Power Delivery and Technical Services</u> Name & Official Title (Please type or print) <u>(813) 739-1213</u> Telephone No. (area code & No.)	 Signature <u>12-7-17</u> Date Signed

XII-B CERTIFICATIONS FOR PERMIT RENEWALS

This is to certify the engineering features of this pollution control project have been examined by me and found to be in conformity with sound engineering principles, applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules of the Department.

_____ Signature	_____ Company Name
_____ Name (please type)	_____ Address
_____ (Affix Seal)	_____ Florida Registration No.:
	_____ Telephone No.:
	_____ Date

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

_____ Name & Official Title (Please type or print)	_____ Signature
_____ Telephone No. (area code & No.)	_____ Date Signed

PLEASE PRINT OR TYPE ONLY: You may report some or all of this information on separate sheets instead of completing these pages. Use the same format. SEE INSTRUCTIONS.

VII. INTAKE AND EFFLUENT CHARACTERISTICS

PART A - You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. Pollutant	2. Effluent						3.. Units		4. Intake (optional)			
	a. Max. Daily Value		b. Max. 30-day Value		c. Annual Avg. Value		d. No. of Analyses	a. Concentration	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
	(1) Conc.	(2) Mass	(1) Conc.	(2) Mass	(1) Conc.	(2) Mass				(1) Conc.	(2) Mass	
a. Carbonaceous Biochemical Oxygen Demand (CBOD)	5.9	486			5.9	378	1	mg/L	lb/day			
b. Chemical Oxygen Demand (COD)	157	12,921			157	10,062	1	mg/L	lb/day			
c. Total Organic Carbon (TOC)	35.7	2,938			35.7	2,288	1	mg/L	lb/day			
d. Total Suspended Solids (TSS)	23	1,893			23	1,474	1	mg/L	lb/day			
e. Total Nitrogen (as N)	7.29	600			7.29	467	51	mg/L	lb/day	1.5	90.9	51
f. Total Phosphorus (as P)	0.184	15			0.184	11.79	8	mg/L	lb/day			
g. Ammonia (as N)	1.83	151			1.83	117	8	mg/L	lb/day			
h. Flow - actual or projected	Value 7.46		Value		Value 5.72		1,051,200	MGD		Value		
i. Flow - design	Value 9.85		Value		Value			MGD		Value		
j. Specific Conductivity	Value 7,700		Value		Value 6,642		1,051,200	µmhos/cm		Value		
k. Temperature (winter)	Value 85.1		Value		Value 72		1,051,200	°C		Value		
l. Temperature (summer)	Value 93.6		Value		Value 88		1,051,200	°C		Value		
m. . pH	Min. 6.6	Max. 7.6	Min.	Max.				STANDARD UNITS				

PART B - Mark "X" in column 2a for each pollutant you know or have reason to believe is present. Mark "X" in column 2b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. Pollutant and CAS No. (if available)	2. Mark "X"		3. Effluent						4. Units		5. Intake (optional)			
	a. be- lieved present	b. be- lieved absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Conc.	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
			(1) Conc...	(2) Mass	(1) Conc.	(2) Mass	(1) Conc.	(2) Mass				(1) Conc.	(2) Mass	
a. Bromide (24949-67-9)	☒	☐	7.59	472					1	mg/L	lb/day			
b. Chlorine, Total Residual	☒	☐	<0.01	1					22	mg/L	lb/day			
c. Color	☒	☐	63						1	Color units				
d. Fecal Coliform	☒	☐	>1,200	3.384E+11					1	CFU/100 mL	CFU			
e. Fluoride (16984-48-8)	☒	☐	0.36	22					1	mg/L	lb/day			
f. Nitrate-Nitrite (as N)	☒	☐	1.38	86					51	mg/L	lb/day			

1. Pollutant and CAS No. (if available)	2. Mark "X"		3. Effluent						4. Units		5. Intake (optional)			
	a. be- lieved present	b. be- lieved absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Conc.	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
			(1) Conc.	(2) Mass	(1) Conc.	(2) Mass	(1) Conc.	(2) Mass				(1) Conc.	(2) Mass	
g. Nitrogen, Total Organic (as N)	☒	☐	2.41	150					1	mg/L	lb/day			
h. Oil and grease	☒	☐	2.4	149					104	mg/L				
i. Phosphorus, Total (as P) (7723-14-0)	☒	☐	0.184	11					1	mg/L	lb/day			
j. Radioactivity														
(1) Alpha, Total	☒	☐	13.2	3.72E+08						pCi/L	pCi/day			
(2) Beta, Total	☒	☐	51.9	1.46E+09						pCi/L	pCi/day			
(3) Radium, Total	☒	☐	5.5	1.55E+08						pCi/L	pCi/day			
(4) Radium 226, Total	☒	☐	5.7	1.61E+08						pCi/L	pCi/day			
k. Sulfate (as SO ₄) (14808-79-8)	☒	☐	501	31,146					1	mg/L	lb/day			
l. Sulfide (as S)	☐	☒	<0.4	<25										
m. Sulfite (as SO ₃) (14265-45-3)	☒	☐	15.1	939						mg/L	lb/day			
n. Surfactants	☒	☐	0.15	9						mg/L	lb/day			
o. Aluminum, Total (7429-90-5)	☒	☐	340	21						µg/L	lb/day			
p. Barium, Total (7440-39-3)	☒	☐	117	7						µg/L	lb/day			
q. Boron, Total (7440-42-8)	☒	☐	19,200	1,194						µg/L	lb/day			
r. Cobalt, Total (7440-48-4)	☒	☐	0.03	0.0019						µg/L	lb/day			
s. Iron, Total (7439-89-6)	☒	☐	1.33	83						mg/L	lb/day			
t. Magnesium, Total (7439-95-4)	☒	☐	110	6,838						mg/L	lb/day			
u. Molybdenum, Total (7439-98-7)	☒	☐	0.3	0.019						µg/L	lb/day			
v. Manganese, Total (7439-96-5)	☒	☐	248	15						µg/L	lb/day			
w. Tin, Total (7440-31-5)	☒	☐	0.2	0.01						µg/L	lb/day			
x. Titanium, Total (7440-32-6)	☒	☐	6.6	0.41						µg/L	lb/day			

PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2a for all GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2a (secondary industries, non-process wastewater outfalls, and non-required GC/MS fractions), mark "X" in column 2b for each pollutant you know or have reason to believe is present. Mark "X" in column 2c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4-dinitrophenol, or 2-methyl-4,6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (all 7 pages) for each outfall. See instructions for additional details and requirements.

1. Pollutant and CAS No. (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a. testing required	b. believed present	c. believed absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Conc.	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
				(1) Conc.	(2) Mass	(1) Conc.	(2) Mass	(1) Conc.	(2) Mass				(1) Conc.	(2) Mass	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)	☒	☒	☐	<0.2	0.01					1	µg/L	lb/day			
2M. Arsenic, Total (7723-14-0)	☒	☒	☐	0.9	0.06					1	µg/L	lb/day			
3M. Beryllium, Total (7440-41-7)	☒	☒	☐	0.15	0.01					8	µg/L	lb/day			
4M. Cadmium, Total (7440-43-9)	☒	☒	☐	<0.2	0.01					1	µg/L	lb/day			
5M. Chromium, Total (7440-47-3)	☒	☒	☐	<0.5	0.03					1	µg/L	lb/day			
6M. Copper, Total (7440-50-8)	☒	☒	☐	58.3	3.62					8	µg/L	lb/day			
7M. Lead, Total (7439-92-1)	☒	☒	☐	0.67	0.04					1	µg/L	lb/day			
8M. Mercury, Total (7439-97-6)	☒	☒	☐	0.35	0.02					24	µg/L	lb/day			
9M. Nickel, Total (7440-02-0)	☒	☒	☐	23.5	1.46					8	µg/L	lb/day			
10M. Selenium, Total (7782-49-2)	☒	☒	☐	6.6	0.41					24	µg/L	lb/day			
11M. Silver, Total (7440-22-4)	☒	☒	☐	0.07	0.00					8	µg/L	lb/day			
12M. Thallium, Total (7440-28-0)	☒	☒	☐	<0.05	0.0031					1	µg/L	lb/day			
13M. Zinc, Total (7440-66-6)	☒	☒	☐	37.7	2.34					8	µg/L	lb/day			
14M. Cyanide, Total (57-12-5)	☒	☒	☐	0.019	0.0012					24	mg/L	lb/day			
15M. Phenols, Total	☒	☒	☐	0.1	0.01					1	mg/L	lb/day			
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)	☒	☐	☒	<0.427	<0.000027					1	µg/L	lb/day			
GC/MS FRACTION -VOLATILE COMPOUNDS															
1V. Acrolein (107-02-8)	☒	☐	☒	<28	<1.74					1	µg/L	lb/day			
2V. Acrylonitrile (107-13-1)	☒	☐	☒	<1.5	<0.09					1	µg/L	lb/day			

1. Pollutant and CAS No. (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a . testing required	b. be- lieved present	c. be- lieved absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Conc.	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
				(1) Conc.	(2) Mass	(1) Conc.	(2) Mass	(1) Conc.	(2) Mass				(1) Conc.	(2) Mass	
GC/MS FRACTION - VOLATILE COMPOUNDS (continued)															
3V. Benzene (71-43-2)	☒	☐	☒	<0.210	<0.01					1	µg/L	lb/day			
4V. Bis (Chloromethyl) Ether (542-88-1)	☒	☐	☐		<0.03					1	µg/L	lb/day			
5V. Bromoform (75-25-2)	☒	☐	☒	<0.420	<0.03					1	µg/L	lb/day			
6V. Carbon Tetrachloride (56-23-5)	☒	☐	☒	<0.340	<0.02					1	µg/L	lb/day			
7V Chlorobenzene (108-90-7)	☒	☐	☒	<0.160	<0.01					1	µg/L	lb/day			
8V. Chlorodi- bromomethane (124-8-1)	☒	☒	☐	2.39	<0.15					1	µg/L	lb/day			
9V. Chloroethane (74-00-3)	☒	☐	☒	<0.520	<0.03					1	µg/L	lb/day			
10V. 2-Chloro-ethylvinyl Ether (110-75-8)	☒	☐	☒	<2.20	<0.14					1	µg/L	lb/day			
11V. Chloroform (67-86-3)	☒	☒	☐	6.06	<0.38					1	µg/L	lb/day			
12V. Dichloro- bromomethane (75-24-4)	☒	☒	☐	5.86	<0.36					1	µg/L	lb/day			
13V. Dichloro- difluoromethane (75-71-8)	☒	☐	☒	<0.230	<0.01					1	µg/L	lb/day			
14V. 1,1-Dichloroethane (75-34-3)	☒	☐	☒	<0.300	<0.02					1	µg/L	lb/day			
15V. 1,2-Dichloroethane (107-06-2)	☒	☐	☒	<0.220	<0.01					1	µg/L	lb/day			
16V. 1,1-Dichloroethylene (75-35-4)	☒	☐	☒	<0.160	<0.01					1	µg/L	lb/day			
17V. 1,2,-Dichloropropane (78-87-5)	☒	☐	☒	<0.190	<0.01					1	µg/L	lb/day			
18V. 1,3-Dichloropropylene (542-75-6)	☒	☐	☒	<0.230	<0.01					1	µg/L	lb/day			
19V. Ethylbenzene (100-41-4)	☒	☐	☒	<0.210	<0.01					1	µg/L	lb/day			
20V. Methyl Bromide (74-83-9)	☒	☐	☒	<2.30	<0.14					1	µg/L	lb/day			
21V. Methyl Chloride (74-87-3)	☒	☐	☒	<3.60	<0.22					1	µg/L	lb/day			
22V. Methylene Chloride (74-98-2)	☒	☐	☒	<0.210	<0.01					1	µg/L	lb/day			
23V. 1,1,2,2-Tetra- chloroethane (79-34-5)	☒	☐	☒	<0.290	<0.02					1	µg/L	lb/day			
24V. Tetrachloroethylene (127-18-4)	☒	☐	☒	<0.22	<0.01					1	µg/L	lb/day			

1. Pollutant and CAS No. (if available)	2. Mark "X"			3. Effluent								4. Units		5. Intake (optional)		
	a . testing required	b. be- lieved present	c. be- lieved absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Conc.	b. Mass	a. Long Term Avg. Value		b. No. of Analyses	
				(1) Conc.	(2) Mass	(1) Conc.	(2) Mass	(1) Conc.	(2) Mass				(1) Conc.	(2) Mass		
GC/MS FRACTION - VOLATILE COMPOUNDS (continued)																
25V. Toluene (108-88-3)	☒	☒	☐	0.21	<0.01					1	µg/L	lb/day				
26V. 1,2-Trans-Dichloroethylene (156-60-5)	☒	☐	☒	<0.190	<0.01					1	µg/L	lb/day				
27V. 1,1,2-Trichloroethane (71-55-6)	☒	☐	☒	0.17	<0.01					1	µg/L	lb/day				
28V. 1,1,2-Trichloroethane (79-00-5)	☒	☐	☒	<0.400	<0.02					1	µg/L	lb/day				
29V. Trichloroethylene (79-01-6)	☒	☐	☒	<0.0360	<0.00					1	µg/L	lb/day				
30V. Trichloro-fluoromethane (75-69-4)	☒	☐	☒	<0.240	<0.01					1	µg/L	lb/day				
31V. Vinyl Chloride (75-01-4)	☒	☐	☒	<0.360	<0.02					1	µg/L	lb/day				
GC/MS FRACTION - ACID COMPOUNDS																
1A. 2-Chlorophenol (95-57-8)	☒	☐	☒	<1.20	<0.07					1	µg/L	lb/day				
2A. 2,4-Dichlorophenol (120-83-2)	☒	☐	☒	<1.20	<0.10					1	µg/L	lb/day				
3A. 2,4-Dimethylphenol (105-67-9)	☒	☐	☒	<1.50	<0.12					1	µg/L	lb/day				
4A. 4,6-Dinitro-O-Cresol (534-53-1)	☒	☐	☒	<1.00	<0.08					1	µg/L	lb/day				
5A. 2,4-Dinitrophenol (51-28-5)	☒	☐	☒	<0.760	<0.06					1	µg/L	lb/day				
6A. 2-Nitrophenol (88-75-5)	☒	☐	☒	<1.4	<0.11					1	µg/L	lb/day				
7A. 4-Nitrophenol (100-02-7)	☒	☐	☒	<1.8	<0.15					1	µg/L	lb/day				
8A P-Chloro-M-Cresol (59-50-7)	☒	☐	☒	<1.80	<0.15					1	µg/L	lb/day				
9A Pentachlorophenol (87-86-5)	☒	☐	☒	<1.10	<0.09					1	µg/L	lb/day				
10A Phenol (108-95-2)	☒	☐	☒	<0.590	<0.05					1	µg/L	lb/day				
11A 2,4,5-Trichloro-phenol (88-06-2)	☒	☐	☒	<0.890	<0.07					1	µg/L	lb/day				
GC/MS FRACTION - BASE/NEUTRAL COMPOUNDS																
1B. Acenaphthene (63-32-9)	☒	☒	☐	4.2	<0.26					1	µg/L	lb/day				
2B. Acenaphthylene (208-96-8)	☒	☐	☒	<0.990	<0.06					1	µg/L	lb/day				
3B. Anthracene (120-12-7)	☒	☐	☒	<1.60	<0.10					1	µg/L	lb/day				
4B. Benzidine (92-87-5)	☒	☐	☒	<2.90	<0.18					1	µg/L	lb/day				

1. Pollutant and CAS No. (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a . testing required	b. be- lieved present	c. be- lieved absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Conc.	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
				(1) Conc.	(2) Mass	(1) Conc.	(2) Mass	(1) Conc.	(2) Mass				(1) Conc.	(2) Mass	
5B. Benzo (a) Anthracene (56-55-3)	☒	☐	☒	<1.00	<0.07					1	µg/L	lb/day			
6B. Benzo (a) Pyrene (50-32-8)	☒	☐	☒	<1.20	<0.07					1	µg/L	lb/day			
7B. 3,4-Benzo-fluoranthene (205-99-2)	☒	☐	☒	<1.00	<0.06					1	µg/L	lb/day			
8B. Benzo (ghi) Perylene (191-24-2)	☒	☐	☒	<1.40	<0.09					1	µg/L	lb/day			
9B. Benzo (k) Fluoranthene (207-08-9)	☒	☐	☒	<1.80	<0.07					1	µg/L	lb/day			
10B. Bis (2-Chloroethoxy) Methane (111-91-1)	☒	☐	☒	<1.20	<0.07					1	µg/L	lb/day			
11B. Bis (2-chloroethyl) Ether (111-44-4)	☒	☐	☒	<1.90	<0.12					1	µg/L	lb/day			
12B. Bis (2-Chloroisopropyl) Ether (102-60-1)	☒	☐	☒	<1.50	<0.09					1	µg/L	lb/day			
13B. Bis (2-Ethylhexyl) Phthalate (117-81-7)	☒	☐	☒	<1.50	<0.09					1	µg/L	lb/day			
14B. 4-Bromophenyl Phenyl Ether (101-55-3)	☒	☐	☒	<1.30	<0.08					1	µg/L	lb/day			
15B Butyl Benzyl Phthalate (84-68-7)	☒	☐	☒	<0.860	<0.05					1	µg/L	lb/day			
16B. 2-Chloronaphthalene (91-58-7)	☒	☐	☒	<4.60	<0.29					1	µg/L	lb/day			
17B. 4-Chlorophenyl Phenyl Ether (7005-72-3)	☒	☐	☒	<0.960	<0.06					1	µg/L	lb/day			
18B. Chrysene (218-01-9)	☒	☐	☒	<1.20	<0.07					1	µg/L	lb/day			
19B. Dibenzo (a,h) Anthracene (53-70-3)	☒	☐	☒	<1.50	<0.09					1	µg/L	lb/day			
20B. 1,2-Dichlorobenzene (95-50-1)	☒	☐	☒	<0.640	<0.04					1	µg/L	lb/day			
21B. 1,3-Dichlorobenzene (541-73-1)	☒	☐	☒	<0.920	<0.06					1	µg/L	lb/day			
22B. 1,4-Dichlorobenzene (106-46-7)	☒	☐	☒	<0.910	<0.06					1	µg/L	lb/day			
23B. 3,3'-Dichlorobenzidine (92-94-1)	☒	☐	☒	<1.40	<0.09					1	µg/L	lb/day			
24B. Diethyl Phthalate (84-66-2)	☒	☐	☒	<1.70	<0.11					1	µg/L	lb/day			
25B. Dimethyl Phthalate (131-11-3)	☒	☐	☒	<1.30	<0.08					1	µg/L	lb/day			
26B. Di-N-Butyl Phthalate (84-74-2)	☒	☐	☒	<2.20	<0.08					1	µg/L	lb/day			
27B. 2,4-Dinitrotoluene (121-14-2)	☒	☐	☒	<1.30	<0.08					1	µg/L	lb/day			
28B. 2,6-Dinitrotoluene (606-20-2)	☒	☐	☒	<1.10	<0.07					1	µg/L	lb/day			

1. Pollutant and CAS No. (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a . testing required	b. be- lieved present	c. be- lieved absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Conc.	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
				(1) Conc.	(2) Mass	(1) Conc.	(2) Mass	(1) Conc.	(2) Mass				(1) Conc.	(2) Mass	
29B. Di-N-Octyl Phthalate (117-84-0)	☒	☐	☒	<2.80	<0.07					1	µg/L	lb/day			
30B. 1,2-Diphenylhydrazine (as Azobenzene) (122-66-7)	☒	☐	☒	<1.20	<0.07					1	µg/L	lb/day			
31B. Fluoranthene (206-44-0)	☒	☐	☒	<1.40	<0.09					1	µg/L	lb/day			
32B. Fluorene (86-73-7)	☒	☐	☒	0.84	<0.05					1	µg/L	lb/day			
33B. Hexachlorobenzene (118-74-1)	☒	☐	☒	<1.70	<0.11					1	µg/L	lb/day			
34B. Hexachlorobutadiene (87-68-3)	☒	☐	☒	<1.20	<0.07					1	µg/L	lb/day			
35B. Hexachloropyrene (77-47-4)	☒	☐	☒	<0.500	<0.03					1	µg/L	lb/day			
36B. Hexachloroethane (67-72-1)	☒	☐	☒	<0.810	<0.05					1	µg/L	lb/day			
37B. Indeno (1,2,3-cd) Pyrene (193-39-5)	☒	☐	☒	<1.70	<0.11					1	µg/L	lb/day			
38B. Isophorone (78-59-1)	☒	☐	☒	<1.80	<0.11					1	µg/L	lb/day			
39B. Naphthalene (91-20-3)	☒	☐	☒	2.07	<0.13					1	µg/L	lb/day			
40B. Nitrobenzene (98-95-9)	☒	☐	☒	<2.10	<0.13					1	µg/L	lb/day			
41B N-Nitrosodimethylamine (62-75-9)	☒	☐	☒	<0.960	<0.06					1	µg/L	lb/day			
42B. N-Nitrosodi-N-Propylamine (621-64-7)	☒	☐	☒	<2.20	<0.14					1	µg/L	lb/day			
43B. N-Nitro-sodiphenylamine (86-30-6)	☒	☐	☒	<1.1	<0.09						µg/L	lb/day			
44B Phenanthrene (85-01-8)	☒	☐	☒	<1.40	<0.09					1	µg/L	lb/day			
45B. Pyrene (129-00-0)	☒	☐	☒	<0.740	<0.04					1	µg/L	lb/day			
46B. 1,2,4-Trichlorobenzene (120-82-1)	☒	☐	☒	<0.600	<0.04					1	µg/L	lb/day			
GC/MS FRACTION - PESTICIDES															
1P. Aldrin (309-00-2)	☐	☐	☒												
2P. -BHC (319-84-6)	☐	☐	☒												
3P -BHC (319-85-7)	☐	☐	☒												
4P. -BHC (58-89-9)	☐	☐	☒												
5P. -BHC (319-86-8)	☐	☐	☒												

1. Pollutant and CAS No. (if available)	2. Mark "X"			3. Effluent						4. Units		5. Intake (optional)			
	a. testing required	b. believed present	c. believed absent	a. Maximum Daily Value		b. Max. 30-day Value (if available)		c. Long Term Avg. Value (if available)		d. No. of Analyses	a. Conc.	b. Mass	a. Long Term Avg. Value		b. No. of Analyses
				(1) Conc.	(2) Mass	(1) Conc.	(2) Mass	(1) Conc.	(2) Mass				(1) Conc.	(2) Mass	
6P. Chlordane (57-74-9)	☐	☐	☒												
7P. 4,4'-DDT (50-29-3)	☐	☐	☒												
8P. 4,4'-DDE (72-55-9)	☐	☐	☒												
9P. 4,4'-DDD (72-54-8)	☐	☐	☒												
10P. Dieldrin (60-57-1)	☐	☐	☒												
11P. -Endosulfan (115-29-7)	☐	☐	☒												
12P. -Endosulfan (115-29-7)	☐	☐	☒												
13P. Endosulfan Sulfate (1031-07-8)	☐	☐	☒												
14P. Endrin (72-20-8)	☐	☐	☒												
15P. Endrin Aldehyde (7421-92-4)	☐	☐	☒												
16P. Heptachlor (76-44-8)	☐	☐	☒												
17P. Heptachlor Epoxide (1024-57-3)	☐	☐	☒												
18P. PCB-1242 (53469-21-9)	☐	☐	☒												
19P. PCB-1254 (11097-69-1)	☐	☐	☒												
20P. PCB-1221 (11104-28-2)	☐	☐	☒												
21P. PCB-1232 (11141-16-5)	☐	☐	☒												
22P. PCB-1248 (12672-29-6)	☐	☐	☒												
23P. PCB-1260 (11096-82-5)	☐	☐	☒												
24P. PCB-1016 (12674-11-2)	☐	☐	☒												
25P. Toxaphene (8001-35-2)	☐	☐	☒												

Attachment 1 – Form 2CS

Narrative Summary

This is an application to revise the National Pollutant Discharge Elimination System (NPDES) permit for the Seminole Electric Cooperative, Inc. (SECI), Seminole Generating Station (SGS) Units 1 and 2 (NPDES Permit No. FL0036498) to include operation of the proposed Seminole Combined-Cycle Facility (SCCF or Project). Coincident with the declared commercial operation of SCCF, SECI intends to permanently remove from service one of the two Existing SGS Units. The proposed SCCF is a two-on-one, natural gas-fired, combined-cycle facility. The Seminole Combined Cycle Facility (SCCF) will have a nominal gross generating capacity of approximately 1,183 megawatts (MW), with a net nominal capacity of approximately 1,050 MW. SECI is currently seeking certification of SCCF under the Power Plant Siting Act (PPSA), Sections 403.501 through .518, Florida Statutes (F.S.), and Chapter 62-17, Florida Administrative Code (F.A.C.). Figures 1 and 2 show the location of the SGS site and the proposed SCCF within the site. The requested revisions to the existing NPDES permit are limited to:

- Revising the SGS water balance flows to reflect the one Remaining SGS Unit and SCCF.
- Using the existing cooling water intake structure in the St. Johns River for SGS Units 1 and 2 to serve the SCCF cooling tower makeup needs.
- Using the existing cooling water blowdown/treated wastewater discharge structure in the St. Johns River to serve the cooling tower blowdown/treated wastewater needs of SCCF.

No other changes to the existing NPDES permit relative to SGS are requested. Also, it should be noted that in February 2017, SECI submitted a renewal application for the existing NPDES permit for SGS Units 1 and 2, which is under review by the Florida Department of Environmental Protection (FDEP). The application to revise the NPDES permit for the proposed SCCF does not change information in the renewal application for SGS Units 1 and 2.

Construction stormwater permit coverage for SCCF will be through an NPDES multisector general construction permit, with notice of intent filed under separate cover.

This narrative summarizes the nature of the surface water intake and wastewater discharges of the proposed SCCF as they relate to relevant aspects of the NPDES permit.

OVERVIEW

Operation of the proposed SCCF will require the use of surface water withdrawn from the St. Johns River and groundwater withdrawn from the Upper Floridan aquifer system, similar to the existing SGS Units 1 and 2 operations. River water will be used for condenser cooling, i.e., cooling tower makeup water, purposes. The primary uses of groundwater will be for steam cycle makeup water and other general plant water needs (collectively “SCCF service water”), which require higher quality water. These include equipment washdown water, pump seals, emergency fire water protection, and evaporative cooler makeup water. Groundwater will also be used for potable water.

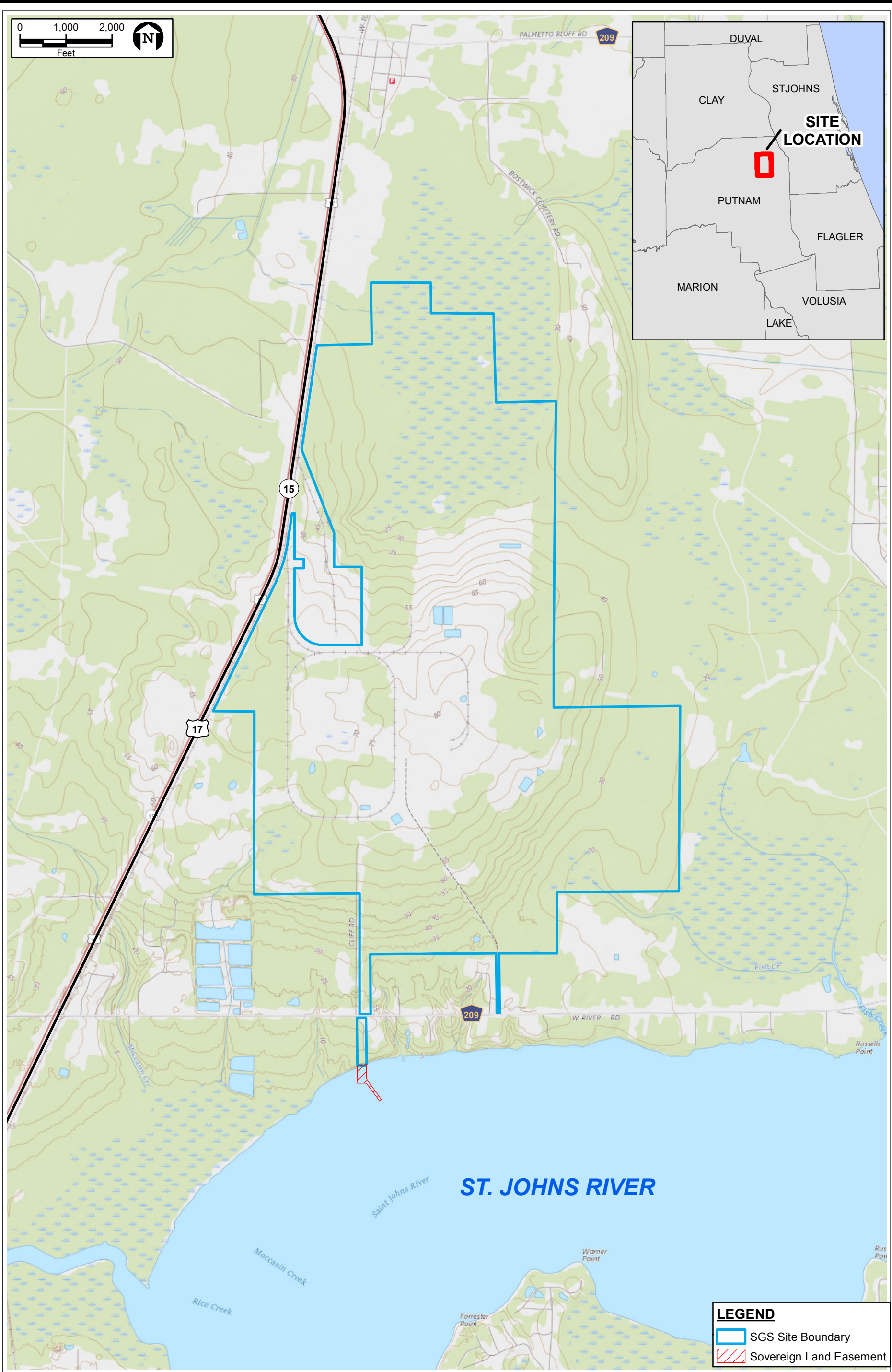


FIGURE 1.
TOPOGRAPHIC MAP OF SGS SITE AND GENERAL VICINITY

Sources: Putnam Co PA, 2016; FDOT, 2016; USGS, 2016; ECT, 2017.



2CS-12

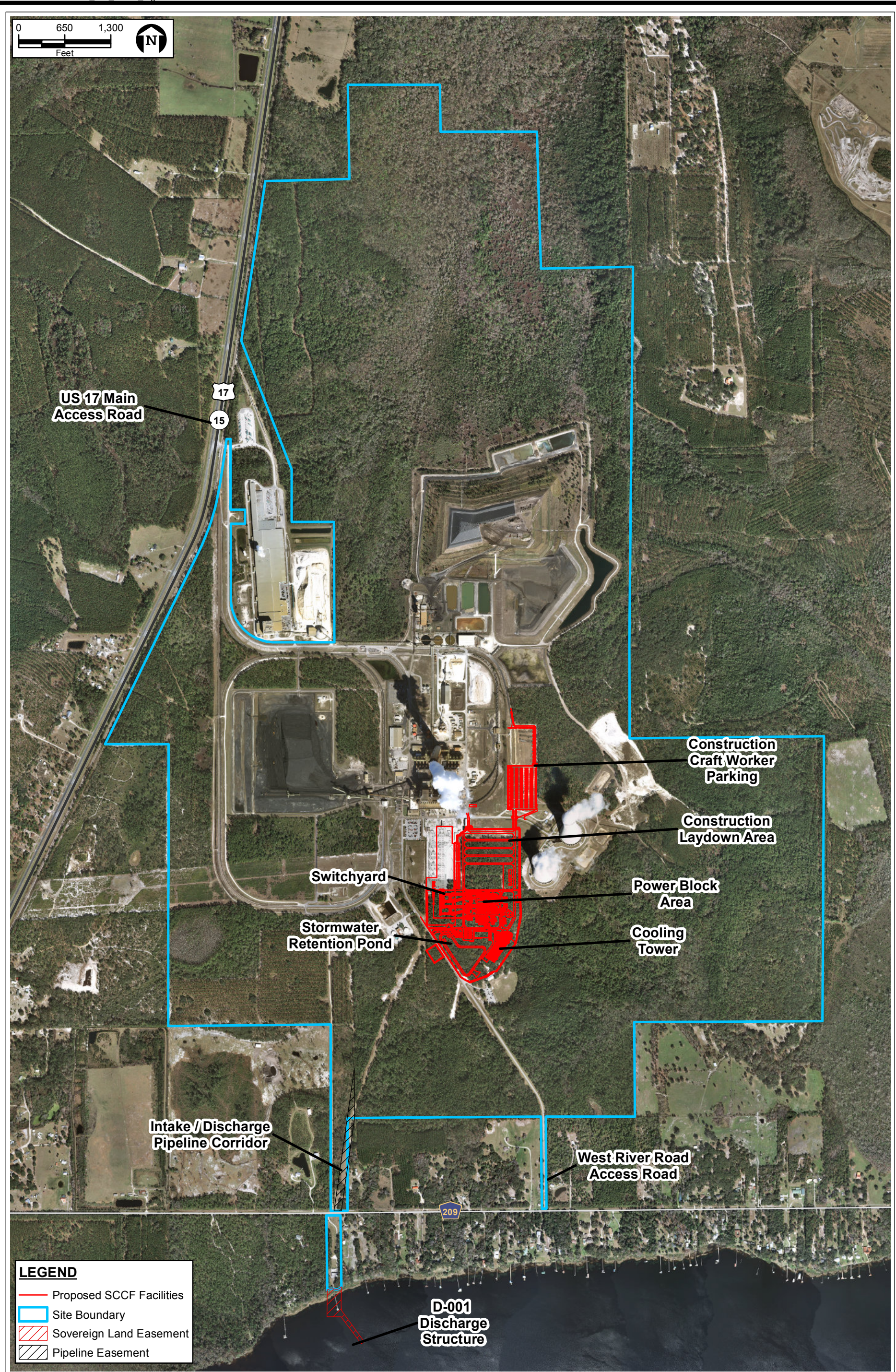


FIGURE 2.
GENERAL LAYOUT OF PROPOSED SCCF FACILITIES ON SGS SITE
SHOWING OUTFALL D-001

Sources: FDOT, 2017; Putnam Co PA, 2016; ECT, 2017.

The qualities of water used in different plant systems will vary with plant operating conditions (i.e., percent capacity or load), as well as with ambient meteorological conditions (i.e., temperature and relative humidity). Figures 3 and 4 present the estimated annual average water use for the Remaining SGS Unit plus SCCF, respectively. Table 1 provides a summary of the major water flows for the annual average and peak operating conditions for SCCF.

Information concerning groundwater use is included in this discussion to provide a comprehensive water balance.

Table 1. Summary of Major Flows/Uses/Reuse in Water Balances for SCCF

Water Flow/Use/Reuse	Water Use (gpm)	
	Annual Average	Peak
<u>River Water</u>		
• Withdrawal for cooling tower makeup	4,814	5,737
• Cooling tower evaporation	3,539	4,219
• Reuse for HRSG quench water	64	70
• Cooling tower blowdown discharge	1,297	1,559
• Total discharge to river (river water and groundwater)	1,393	1,660
<u>Groundwater</u>		
• Plant service water	212	286
• Potable/sanitary water	1	1
• Total withdrawal	213	287
• Reuse for cooling tower makeup	23	42

Sources: Black & Veatch, 2016.
ECT, 2016.

WATER SUPPLY AND DISCHARGE

As shown in Table 1, the use of river surface water withdrawn from the St. Johns River for cooling tower makeup water is by far the largest plant water use. The makeup water will be withdrawn through the existing river intake structure and pipeline for SGS Units 1 and 2. Cooling tower makeup water is required to replace water lost through evaporation in the condenser cooling process and manage water quality within the cooling system to avoid equipment fouling and damage. The blowdown water will be discharged to the river through the existing pipeline and discharge structure for SGS Units 1 and 2. Approximately 30 percent of the cooling tower makeup water withdrawn from the St. Johns is discharged back into the river. The cooling water system will be compliant with Clean Water Act (CWA) Section 316(b) requirements applicable to new units at existing facilities, because it employs a closed-cycle recirculating cooling system.

2CS-14

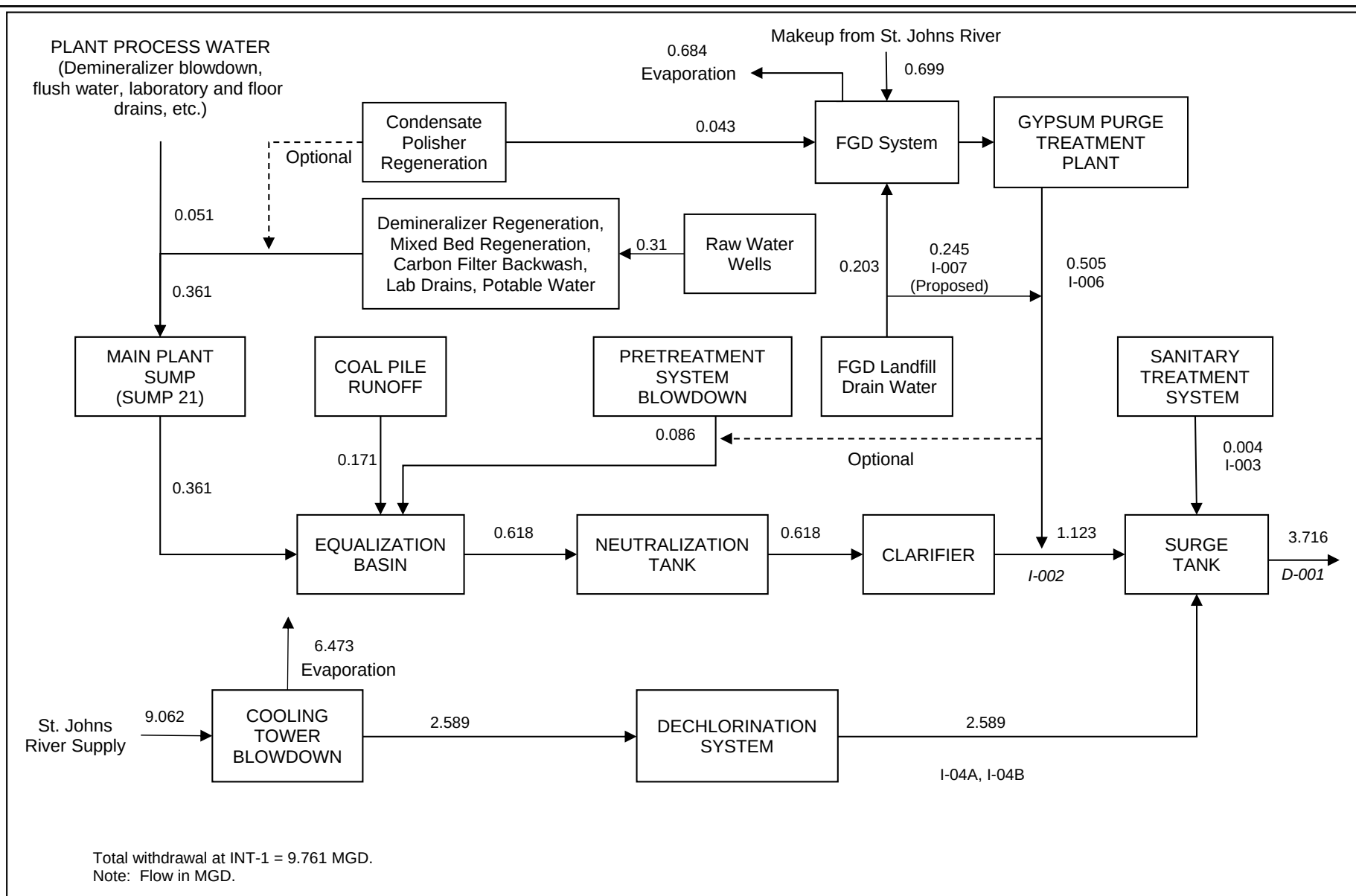


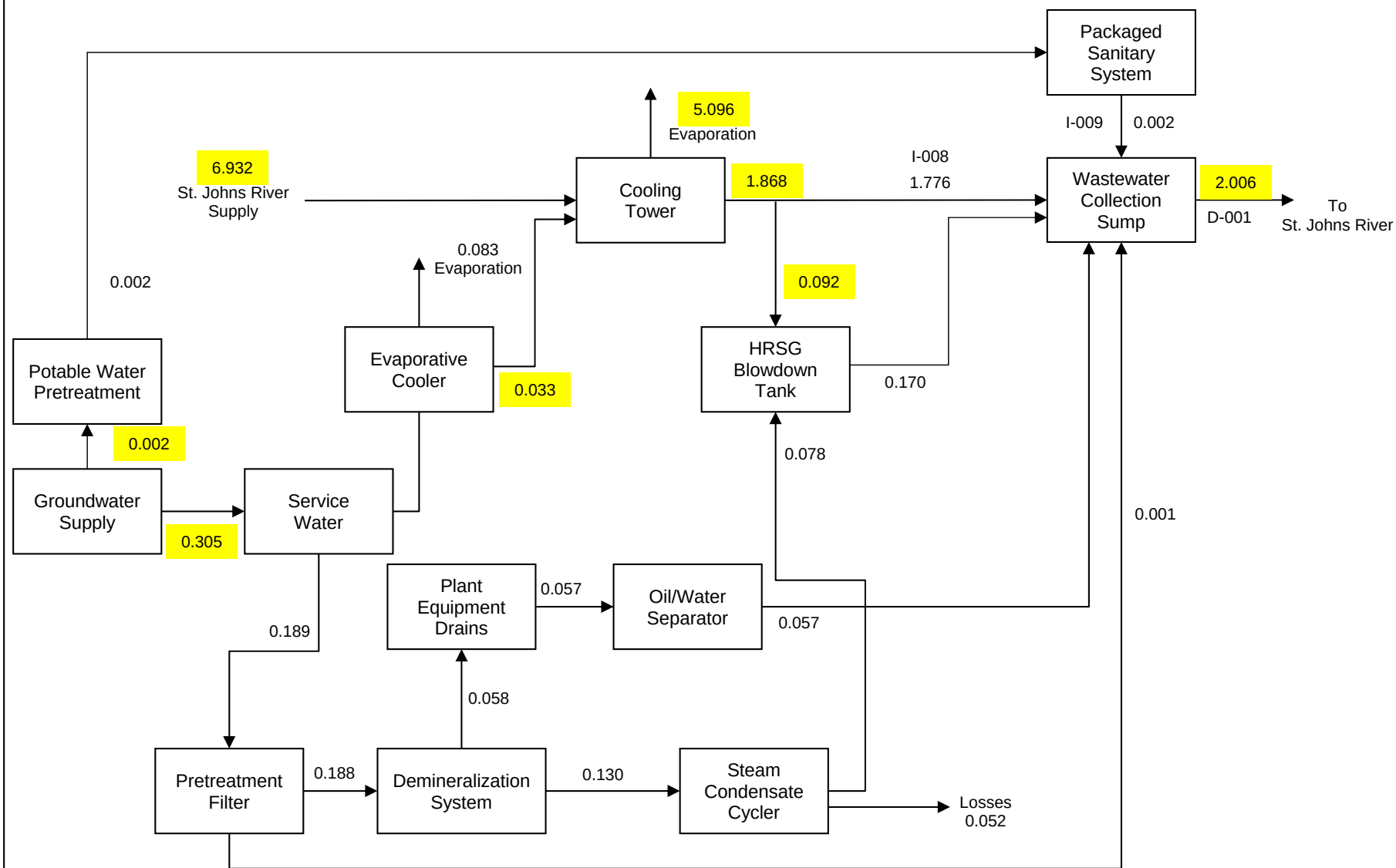
FIGURE 3.

AVERAGE WATER BALANCE FLOW DIAGRAM—REMAINING SGS UNIT

Source: ECT, 2017.



2CS-15



Highlighted flows included in Table 1.

Note: Flow in MGD.

FIGURE 4.

AVERAGE WATER BALANCE FLOW DIAGRAM—PROPOSED SCCF AT SGS

Source: ECT, 2017.



Under the existing conditions of certification (COCs) for SGS Units 1 and 2, COC B.III.B.3 from the St. Johns River Water Management District (SJRWMD) allows a maximum annual surface water withdrawal from the St. Johns River for cooling tower makeup and SGS service water use¹ of up to 15,783 million gallons per year (MGY). This water volume represents an average daily withdrawal of approximately 43.24 million gallons per day (MGD). As shown in Figure 2, the proposed annual average river water withdrawals for SCCF will be approximately 6.932 MGD or 2,350 MGY. The estimated withdrawal from the St. Johns River for the one Remaining SGS Unit is expected to be 9.761 MGD (annual average daily flow). Based on these uses, the total annual combined surface water withdrawals for SCCF and the Remaining SGS Unit are projected to be approximately 16.693 MGD or 6,093 MGY. Therefore, a sufficient surface water use allocation is available under the existing approved withdrawals for SGS to serve the needs of SCCF. No additional surface water use is requested in this SCA.

As shown in Table 1, the total groundwater withdrawals for SCCF will be 213 gpm (0.307 MGD) on an annual average basis and 287 gpm (0.413 MGD) on a peak daily basis. Groundwater will be primarily used for SCCF service water. These uses require higher quality fresh groundwater instead of tidally influenced river water. Even with higher quality, the groundwater will require additional treatment (i.e., filtration and demineralization) prior to use for heat recovery steam generator (HRSG) steam cycle makeup, equipment wash water, and pump seals. Groundwater will also be used for potable water. Potable water will be treated in an on-site, appropriately designed potable water treatment system. The groundwater will be provided through withdrawals from two new SCCF service water wells and one new potable water well installed in the area of SCCF.

The cooling tower makeup water will be supplied with water withdrawn from the existing SGS intake structure located in the St. Johns River that currently supplies cooling water for SGS Units 1 and 2 through a 503-foot (ft), 36-inch ductile iron pipe. The average daily flow from the St. Johns River through the intake for SCCF is 6.932 MGD, with a maximum daily withdrawal of 8.261 MGD. This quantity, combined with the proposed withdrawal from the Remaining SGS Unit, will be within current permit limitation of 43.24 MGD. The average daily evaporation from the SCCF cooling tower is projected to be 5.096 MGD with a maximum daily value 6.075 MGD.

The condenser cooling system for the combined-cycle units will consist of one multiple-cell induced mechanical draft cooling tower for heat dissipation. The cooling tower will be designed to remove approximately 2.083 billion British thermal units per hour. The average makeup water to the tower includes 4,814 gallons per minute (gpm) from the river and 23 gpm from the evaporative cooler blowdown. The maximum makeup water rate includes 5,737 gpm from the river and 42 gpm from the evaporative cooler blowdown. The proposed cooling tower is designed to typically operate at approximately 3.5 cycles of concentration.

The existing SGS intake configuration will retain the existing trash racks. Intake flow will be limited to a design maximum through-screen velocity of 0.5 foot per second (fps). This maximum design intake velocity is considered by the U.S. Environmental Protection Agency (EPA), in its final Section 316(b) rule for existing facilities, as one of the alternatives for best technology available (BTA) to mitigate for impingement effects at cooling water intakes, as per Title 40, Part 125.94(b)(2), Code of Federal Regulations (CFR).

Approximately 95 percent of the cooling tower blowdown will be discharged to the wastewater collection sump and combined with the discharge from the Remaining SGS Unit before being discharged through an approximately 900-ft, 16-inch ductile iron pipe to Outfall D-001. Outfall D-001 consists of a 15-nozzle, 28-ft, multiple-port diffuser. The average discharge temperature at Outfall D-001 is anticipated to be 86 degrees Fahrenheit (°F), with a maximum discharge temperature of 95°F. The approximate average travel time from condenser inlet to the point of discharge is calculated as 32.5 minutes.

¹ “SGS service water” refers to water used for equipment washdown, pump seals, and boiler makeup water.

Prior to discharge, SCCF cooling tower blowdown will be combined with other treated low-volume wastewaters, including filter reject water, contact stormwater and equipment drains treated in the oil/water separator, and treated sanitary wastewater effluent. Each of these waste streams will be combined in the wastewater collection sump prior to discharge. Effluent from the wastewater collection sump will be combined with the blowdown and other effluents from the Remaining SGS Unit and then discharged to the St. Johns River through the existing multiple-port diffuser.

The point of discharge of Outfall D-001 is located approximately 900 ft from the north shore of the St. Johns River. The discharge is through a 16-inch diameter, submerged ductile iron pipe. The submerged discharge pipe runs in a northwest-to-southeast direction. The orientation of the discharge pipe is 144.7 degrees (°) measured clockwise from the north. The end of the pipe is fitted with a 15-port, 28-ft diffuser. Each riser is 6 inches in diameter with 2-ft spacing between the risers. At the end of each riser is a 2-inch reducer/nozzle. Each port of the diffuser is oriented upward at a 20° angle to the horizontal level. The discharge port is approximately 8 ft below mean sea level.

The discharge pipe runs parallel to the intake pipe (under the access bridge). The discharge pipe is submerged for the length of the intake pipe. Following the intake structure, the discharge pipe follows the contours of the river bottom (exposed). The discharge pipe effectively avoids any sensitive vegetation beds that occur between the intake structure and the shoreline as it discharges at a depth that encourages mixing in deep waters (as compared to closer to shore).

MINIMIZATION AND REUSE

SECI has evaluated the proposed SCCF water use in an integrated fashion and reduced its overall water withdrawals by employing a closed-cycle recirculating cooling system, as well as combined-cycle generation technology. The closed-cycle cooling system will consist of mechanical draft, evaporative cooling towers supplied with river water for makeup to avoid use of groundwater, as well as to take advantage of the existing SGS intake and discharge structures. Use of closed-cycle cooling and combined-cycle generation will reduce facility cooling water demand by more than 95 percent relative to an open-cycle facility of the same electrical output. Use of closed-cycle cooling is also a basis of compliance for new units² at existing facilities as defined in EPA's 2014 316(b) existing facilities intake rule, which aims to reduce adverse environmental impacts associated with impingement and entrainment of aquatic organisms.

SECI has also carefully considered opportunities for water reuse, either from inside the plant itself or from outside the plant, and water conservation to minimize the use of groundwater. No practical sources of reclaimed water are available in the region. Similarly, potential storage and reuse of stormwater on the site is impractical due to the soil conditions on the site and constraints posed by wetlands and other land features.

MINIMIZATION OF POTENTIAL WATER QUALITY IMPACTS

SECI has taken several measures to reduce the potential for impacts to water quality including:

- Use of closed-cycle cooling and combined-cycle generation to reduce water demand for cooling. Together, surface water intake will be reduced by more than 95 percent relative to similar steam electric generating plants that use open-cycle cooling.
- Use of combined-cycle generation and closed-cycle cooling substantially reduces thermal loading to the environment. This reduction is manifested in reduced flows as well as reduced

² SCCF will be considered a new unit at an existing facility according to the definitions in the final 316(b) existing facilities rule.

effluent temperatures. SECI conservatively estimates the maximum effluent temperature will be well below the thermal limitation in the existing NPDES permit.

- SCCF will be operated in compliance with applicable state and federal regulations, including effluent limitation guidelines, water quality-based effluent limitations, and Florida's antidegradation policy.
- Chemical metal cleaning wastes will be containerized and disposed of offsite consistent with local, state, and federal regulations.
- Low-volume process wastewater will be appropriately treated and discharged in combination with cooling tower blowdown.

Table 2. Locations and Methods of Flow Measurements

2CS, Section IV.E

List the method(s) and location(s) of flow measurement:

- #001—Magnetic flow meter in the surge tank discharge line
 - #002—Magnetic flow meter in the discharge line from the pump suction tank
 - #003—Totalizer in the effluent sump discharge line
 - #004A—Magnetic flow meter in the blow down line
 - #004B—Magnetic flow meter in the blow down line
 - #005—Magnetic flow meters in the two influent lines
-

Attachment 2 – Form 2CS

Antidegradation Demonstration

The discharge from the proposed SCCF will not result in degradation of water quality or impairment of any of the designated uses in the receiving body of water. The operation of SCCF, in combination with the Remaining SGS Unit will not result in adverse impacts to aquatic resources.

A site certification application (SCA) has been submitted to the state that addresses the potential effects of the construction and operation of SCCF. The benefits of the Project are also described in the SCA. While SCCF is not expected to result in degradation of water quality, the following information is provided to demonstrate the proposed discharge is consistent with the antidegradation policy set forth in Rule 62-302.300, Florida Administrative Code (F.A.C.), and meets the antidegradation permitting requirements in Rules 62-4.242(1)(b) and (d), F.A.C.

ANTIDEGRADATION PROVISIONS

Section 403.088(2)(b), Florida Statutes (F.S.) provides that, if a proposed discharge does not reduce the quality of the receiving water below the classification established for it, the Florida Department of Environmental Protection (FDEP) “may issue an operation permit if it finds that such degradation is necessary or desirable under federal standards and under circumstances which are clearly in the public interest.”

Rule 62-4.242(1), F.A.C. provides:

- (b) In determining whether a proposed discharge which results in water quality degradation is necessary or desirable under federal standards and under circumstances which are clearly in the public interest, the department shall consider and balance the following factors:
 - 1. Whether the proposed Project is important to and is beneficial to the public health, safety, or welfare (taking into account the policies set forth in Rules 62-302.300, F.A.C., and, if applicable, 62-302.700, F.A.C.); and
 - 2. Whether the proposed discharge will adversely affect conservation of fish and wildlife, including endangered or threatened species, or their habitats; and
 - 3. Whether the proposed discharge will adversely affect the fishing or water-based recreational values or marine productivity in the vicinity of the proposed discharge; and
 - 4. Whether the proposed discharge is consistent with any applicable Surface Water Improvement and Management Plan that has been adopted by a Water Management District and approved by the Department.

* * *

- (d) For industrial wastewater facilities, proposing new or expanded surface water discharges, in addition to paragraph (b) above, in order for the new or expanded industrial wastewater discharge to be necessary or desirable under federal standards and under circumstances which are clearly in the public interest, the permit applicant:

1. Must demonstrate that use of other discharge locations, land application, or recycling at off-Site locations that would avoid the degradation of water quality is not economically and technologically reasonable; and
2. Shall submit a signed statement under penalty of law that a waste minimization and source reduction analysis was completed consistent with best management practices appropriate for the type of facility or discharge proposed as identified in paragraph 62-620.100(3)(m), F.A.C., 40 CFR 122.44(k), and Guidance Manual for Developing Best Management Practices (BMP), U.S. Environmental Protection Agency, Office of Water, Washington, DC, EPA 833-B-93-004, October 1993.

Rule 62-302.300(6), F.A.C., confirms that “private activities conducted for private purposes may...be in the public interest.” These elements of the antidegradation rule are addressed in the following paragraphs.

RULE 62-4.242(1)(b), F.A.C.

1. SCCF is important and beneficial to the public health, safety, and welfare of the region by providing reliable and cost-effective electric power. Through its integrated resource planning process, SECI has determined the need for additional capacity by 2021. SCCF is among the key components chosen by SECI’s integrated planning process to meet this capacity need in a manner that promotes cost-effectiveness and system reliability. SECI will file a petition for a determination of need for SCCF with the Florida Public Service Commission (PSC). The PSC is the sole forum for a determination of the need for an electrical power plant (Section 403.519, F.S.).
2. The proposed discharge will not adversely affect conservation of fish and wildlife, including endangered or threatened species, or their habitats.
3. The proposed discharge will not adversely affect the fishing or water-based recreational values or marine productivity in the vicinity of the proposed discharge.

The conclusions articulated in previous Items 2 and 3 are supported by the following:

- The rate of cooling water withdrawn from the existing SGS intake structure for the SCCF closed-cycle recirculating cooling system will be more than 95 percent less compared to a facility with the same output that employs once-through cooling, thus producing a commensurate decrease in impingement and entrainment rates.
- The design intake flow for new units at existing facilities must be commensurate with that which can be attained by use of a closed-cycle recirculating system under 40 CFR 125.94(e). The existing SGS intake structure will have a design through-screen velocity of less than 0.5 fps, considered BTA for mitigation of impingement mortality effects from existing cooling water intakes per 40 CFR 125.94(c)(2).
- The current NPDES permit sets a maximum discharge temperature at the point of discharge into the St. Johns River of 98.9°F as a maximum for compliance with the 316(a) thermal variance. The cooling tower design for the new SCCF unit will result in a cooling tower blowdown temperature that is lower than this permitted discharge limit.
- The effluent from SCCF will comply with applicable ambient water quality standards.
- SCCF will intermittently use sodium hypochlorite to control biofouling in the cooling tower, similar to existing SGS operations for Units 1 and 2 and consistent with the 40 CFR 423

effluent guidelines for the steam electric generating sector. Dechlorination will be performed during this procedure.

- No other chemical compounds will be introduced into the cooling tower blowdown, which is expected to be similar in quality to the blowdown from the existing Units 1 and 2 cooling towers. Quarterly toxicity testing of the SGS discharge conducted under conditions of the current NPDES permit for those units has shown no issues with toxicity.
- There are no applicable surface water improvement and management (SWIM) plans adopted by a Water Management District and approved by FDEP that would be impacted by the Project.

RULE 62-4.242(1)(d), F.A.C.

1. Discharge of cooling tower blowdown via the existing SGS discharge structure is the most cost-effective and least environmentally disturbing discharge alternative due the presence of existing infrastructure and close proximity. Land application and offsite reuse of the cooling tower blowdown is not feasible due to the use of tidally influenced river water for cooling tower makeup and the resulting elevated dissolved solids content of the cooling blowdown.
2. SECI certifies a waste minimization and source reduction analysis was completed consistent with BMPs to control or abate the discharge of pollutants as identified in Rule 62-620.100(3)(m), F.A.C., and 40 CFR 122.44(k).

In summary, the proposed SCCF is in the public interest, because it helps ensure SECI can provide reliable and cost-effective electric service to its Member cooperatives. The Project will result in substantial reductions in cooling water withdrawals and thermal discharges, minimize adverse environmental impacts due to impingement and entrainment, and will result in additional protection to threatened and endangered species. The Project will not result in degradation of water quality or reduction in any of the designated uses in the receiving water body. SECI currently operates SGS under a BMP3 plan consistent with Rule 62-620.100(3)(m), F.A.C., and 40 CFR 122.44(k). SECI will likewise operate SCCF in accordance with this plan.³

SECI is providing the following statement in accordance with Rule 62-4.242(1)(d)2, F.A.C.:

[A] waste minimization and source reduction analysis was completed consistent with best management practices appropriate for the type of facility or discharge proposed, as identified in Rule 62-620.100(3)(m), F.A.C., 40 CFR 122.44(k), and Guidance Manual for Developing Best Management Practices, U.S. Environmental Protection Agency, Office of Water, Washington, DC, EPA 833-B-93-004, October 1993.

³ Guidance Manual for Developing Best Management Practices, U.S. Environmental Protection Agency, Office of Water, Washington, DC, EPA 833-B-93-004, October 1993

**MIXING ZONE ASSESSMENT FOR
NPDES PERMIT APPLICATION**

**SEMINOLE GENERATING STATION
SEMINOLE COMBINED-CYCLE FACILITY**

(PERMIT No. FL0036498)

Prepared for:



Tampa, Florida

Prepared by:



**3701 Northwest 98th Street
Gainesville, Florida 32606**

ECT No. 150658-0300

November

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LIST OF ACRONYMS AND ABBREVIATIONS

°	degree
°F	degree Fahrenheit
µg/L	microgram per liter
µmhos/cm	micromhos per centimeter
AADF	annual average daily flow
AO	administrative order
cfs	cubic feet per second
EPA	U.S. Environmental Protection Agency
FDEP	Florida Department of Environmental Protection
FGD	flue gas desulfurization
fps	foot per second
kg/m ³	kilogram per cubic meter
m ²	square meter
mg/L	milligram per liter
MGD	million gallons per day
NPDES	National Pollutant Discharge Elimination System
SCR	selective catalytic reduction
SECI	Seminole Electric Cooperative, Inc.
SGS	Seminole Generating Station
USGS	U.S. Geological Survey
WBID	Water Body Identification

PROFESSIONAL ENGINEER CERTIFICATION

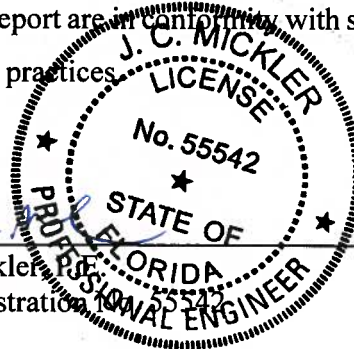
This is to certify that this report, Mixing Zone Assessment for NPDES Permit Application, has been prepared by me. The technical contents of this report are in conformity with sound engineering principles and generally accepted modeling practices.

Prepared by: _____

J. Chris Mickler, P.E.
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352/332-0444

Date: _____



1.0 INTRODUCTION

Seminole Electric Cooperative, Inc. (SECI), owns and operates a coal-fired steam electric generating plant—Seminole Generating Station (SGS)—near Palatka, Florida. SGS discharges various industrial waste streams into the St. Johns River (a Class III water of Florida) authorized by National Pollutant Discharge Elimination System (NPDES) Permit No. FL0036498. The NPDES permit was renewed by Florida Department of Environmental Protection (FDEP) on August 29, 2012, and has undergone various minor revisions predominantly related to process chemical application. The NPDES permit has been administratively continued while the renewal process is ongoing. The renewal application was submitted to FDEP on February 28, 2017, and is currently under review.

The existing NPDES permit provides mixing zones for copper, cyanide, iron, mercury, selenium, specific conductance, and temperature. Table 1-1 presents the effluent limit and permitted mixing zone size for each parameter.

SECI is currently in the process of designing and permitting a facility expansion to include a two-on-one, combined-cycle electric generating unit comprised of two combustion turbine generators, two heat recovery steam generators, and one steam turbine generator, which will discharge effluent from SGS to the St Johns River. The new facility is called the Seminole Combined-Cycle Facility (SCCF or Project). Also, coincident with the declared commercial operation of SCCF, SECI intends to permanently remove from service one of the two Existing SGS Units.

The objective of this water mixing zone report is to serve as a supporting document of the application for a discharge from the new SCCF to be added to the existing discharge from the Remaining SGS Unit. Effluent from the facility will discharge through the existing Outfall D-001.

Table 1-1. Current NPDES Permit Effluent Limits and Permitted Mixing Zone Sizes

Parameter	Current Effluent Limit	Permitted Mixing Zone Size (m ²)
Copper	139 µg/L	723
Cyanide	19.6 µg/L	125
Iron	1.7 mg/L	1.2
Mercury	0.09 µg/L	67,323
Selenium	11.7 µg/L	5.8
Specific conductivity	8,653 µmhos/cm	176
Temperature	98.9°F	2.0
Temperature rise	26.3°F	18.5

Note: °F = degree Fahrenheit.
 µg/L = microgram per liter.
 µmhos/cm = micromhos per centimeter.
 m² = square meter.
 mg/L = milligram per liter.

Source: ECT, 2017.

2.0 FACILITY DESCRIPTION

2.1 PROPOSED WATER BALANCE

Figure 2-1 provides a schematic flow diagram for average flow conditions for the wastewater system for the one Remaining SGS Unit operations. Figure 2-2 provides a schematic flow diagram for the proposed SCCF. The waste stream from the proposed facility will be added to the effluent disposal pipe from the Existing SGS Units prior to the point of discharge, designated as Outfall D-001. The existing discharge to the St. John's River (D-001) includes domestic wastewater (I-003), cooling tower blowdown (I-04A and I-04B), flue gas desulfurization (FGD) purge stream (I-006), and low-volume wastes. The plant low-volume wastes combine with the FGD purge stream prior to mixing with other waste streams forming internal Outfall I-002. The proposed discharge will consist predominantly of domestic wastewater, cooling tower blowdown, and low-volume wastes. Two internal outfalls are proposed for SCCF. These include I-008 from the cooling tower blowdown and I-009 from the domestic wastewater treatment system.

Sources of water used for SGS operations are primarily the St. Johns River and, to a lesser extent, the Upper Floridan aquifer. Water withdrawn from the St. Johns River via the intake (INT-1) is used as condenser cooling water and service water in most plant areas for the Existing SGS Units, as well as the proposed SCCF. Groundwater is and will be used mainly in the boiler for steam generation. Throughout this report, both INT-1 and D-005 represent the intake at the St. Johns River.

The annual average daily flow (AADF) and maximum daily flow rate at D-001 from the Existing SGS Units are 5.66 and 7.40 million gallons per day (MGD), respectively. Most of the effluent comes from the cooling towers (4.244 MGD average), which use the St. Johns River water as their water source. The proposed AADF discharge from the one Remaining SGS Unit to Outfall D-001 is expected to be 3.716 MGD, with a maximum daily flow projected to be 4.6 MGD.

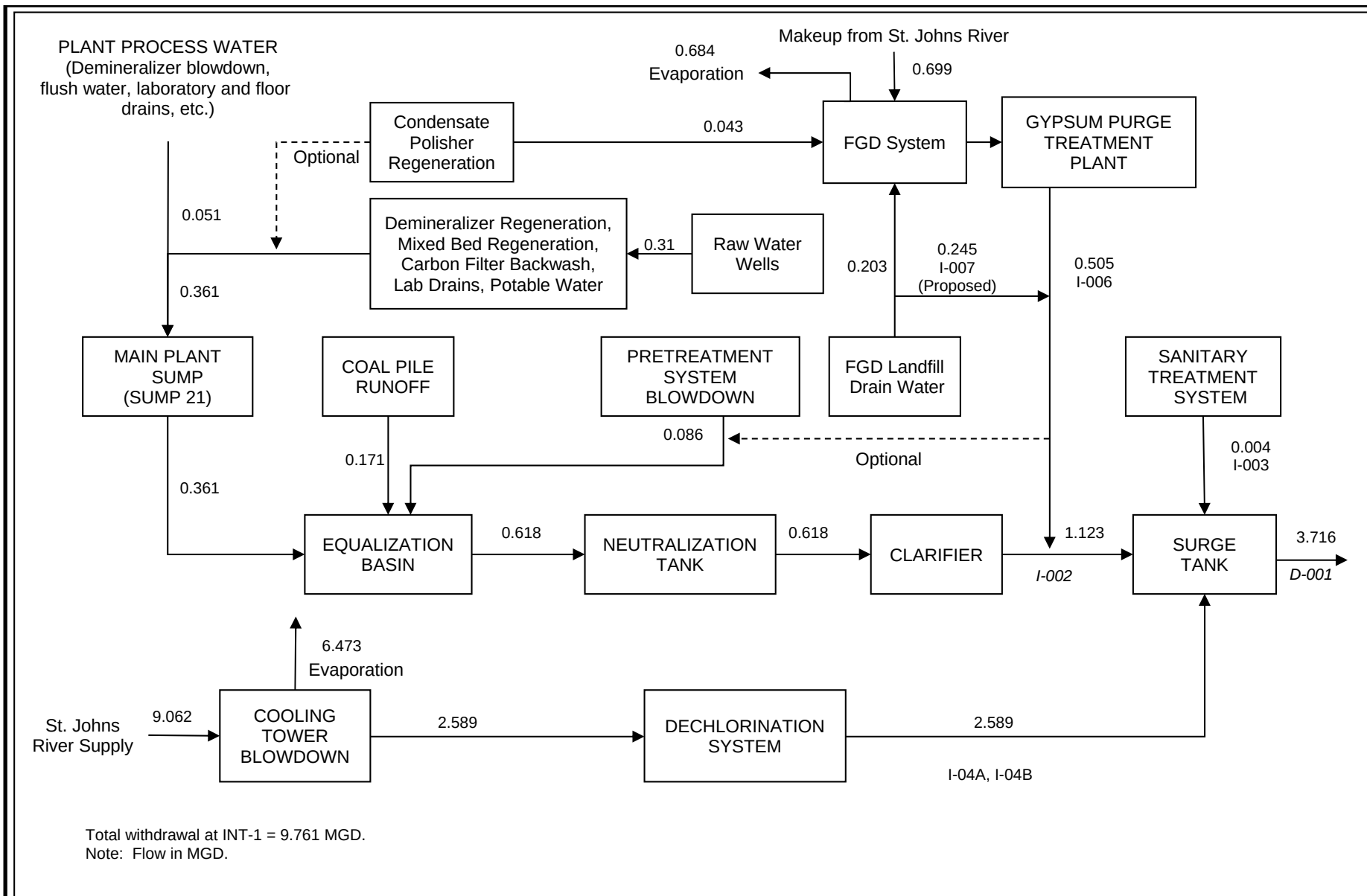
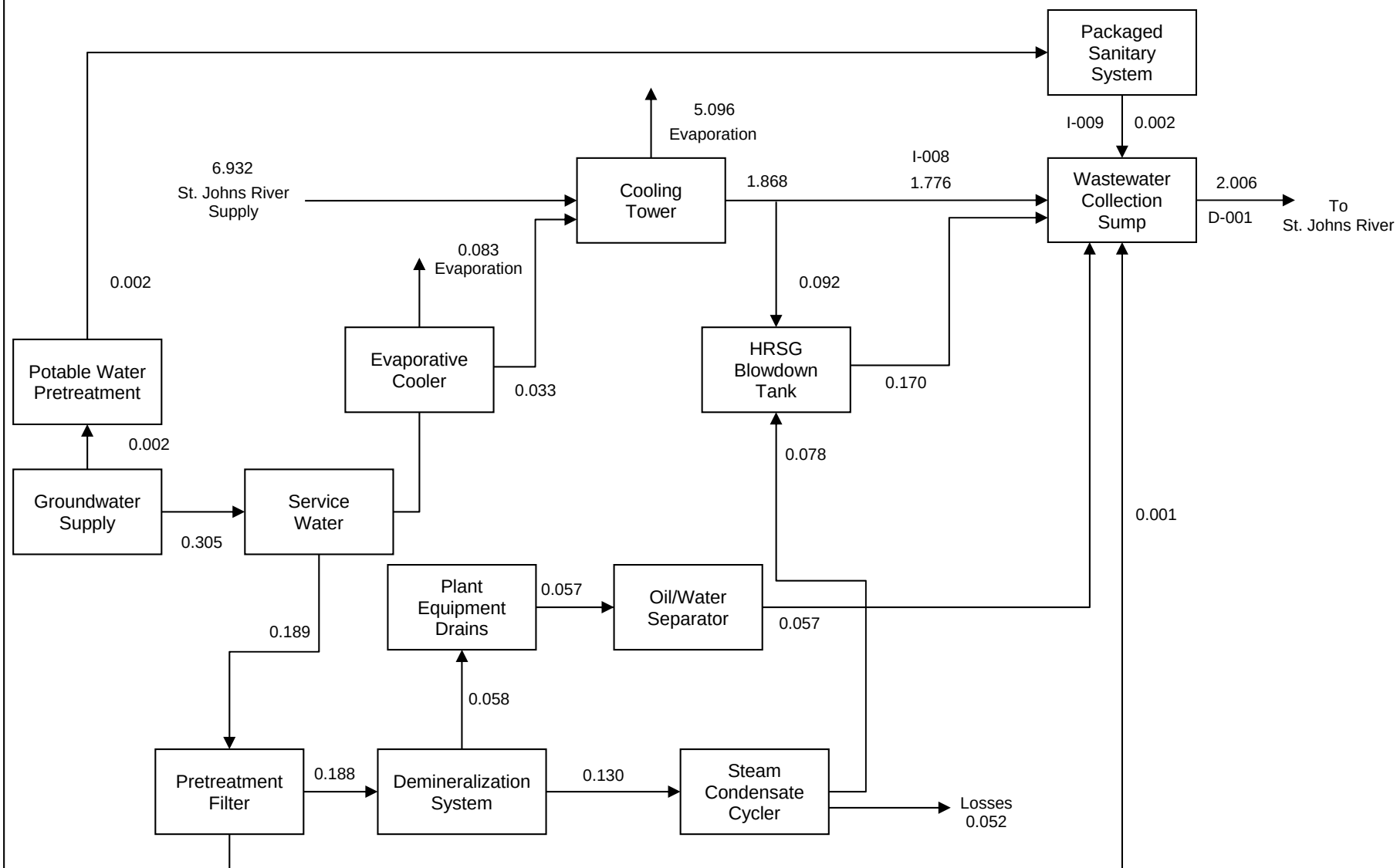


FIGURE 2-1.

AVERAGE WATER BALANCE FLOW DIAGRAM—REMAINING SGS UNIT

Source: ECT, 2017.





Note: Flow in MGD.

FIGURE 2-2.

AVERAGE WATER BALANCE FLOW DIAGRAM—PROPOSED SCCF AT SGS

Source: ECT, 2017.



The AADF and maximum daily flow rate to be added to D-001 for the proposed SCCF will be 2.006 MGD and 2.390 MGD, respectively. Most of the effluent projected to come from the cooling tower (1.947 MGD average) will also use the St. Johns River as its water source. The combined AADF for the Remaining SGS Unit with the proposed SCCF will be 5.72 MGD with a maximum daily flow of 7.67 MGD to be discharged through Outfall D-001.

Therefore, because the majority of the effluent at Outfall D-001 consists of blowdown of noncontact cooling water withdrawn from the river (INT-1), there is no significant net change of the pollutant mass loading to the river. The cooling towers are normally operated at approximately 3.5 cycles of concentration.

2.2 OUTFALL D-001 DISCHARGE STRUCTURE

The point of discharge of Outfall D-001 is located approximately 900' from the north shore of the St. Johns River. The discharge is through a 16-inch diameter, submerged ductile iron pipe. The submerged discharge pipe runs in a northwest to southeast direction. The orientation of the discharge pipe is 144.7 degrees (°) measured clockwise from the north. The end of the pipe is fitted with a 15-port, 28' diffuser. Each riser is 6 inches in diameter with a 2' spacing between the risers. At the end of each riser is a 2-inch reducer/nozzle. Each port of the diffuser is oriented upward at a 20° angle to the horizontal level. The discharge port is approximately 8' below mean sea level.

3.0 EFFLUENT WATER QUALITY AND FLOW DATA

3.1 FLOWS

Figure 2-1 presents the daily flow data at the intake designated as D-005, Outfall D-001, and internal discharge locations I-002 and I-006 for the Remaining SGS Unit. The projected AADF at D-001 of 3.716 MGD represents the estimated daily flow from the one unit. Figure 2-2 presents the projected average daily flow for the proposed SCCF. Table 3-1 presents the projected average flows for each stream for the Remaining SGS Unit combined with the flows for the new SCCF.

3.2 D-001 WATER QUALITY DATA

The following sections present the water quality data at Outfall D-001 for those parameters that require mixing zones. The projected water quality from the proposed SCCF is expected to be similar to the existing discharge, as both the existing and proposed cooling towers are designed to operate at approximately 3.5 cycles of concentration.

3.2.1 TOTAL RECOVERABLE IRON

Figure 3-1 presents the total recoverable iron data at Outfall D-001 from 2001 to the present. The data indicate, since the last permit renewal, the iron concentration was below the effluent limit of 1.7 milligrams per liter (mg/L). Table A-1 in Appendix A presents the iron data values.

3.2.2 TOTAL RECOVERABLE COPPER

Figure 3-2 presents the total recoverable copper data at Outfall D-001 from 2001 to the present. The data indicate, since the last permit renewal, the copper concentration at D-001 was below the effluent limit of 139 micrograms per liter (µg/L). Table A-2 in Appendix A presents the copper data values.

Table 3-1. Average Wastewater Flows for the Remaining SGS Unit Combined with SCCF

Streams	Average Flow (MGD)
D-001	5.72
I-002	1.123
I-04A or I-04B	2.589
I-006	0.505
I-007 (proposed)	0.245 (design)
I-008 (proposed)	1.776 (design)
I-009 (proposed)	0.002 (design)
INT-1	16.693

Source: ECT, 2017.

3-3

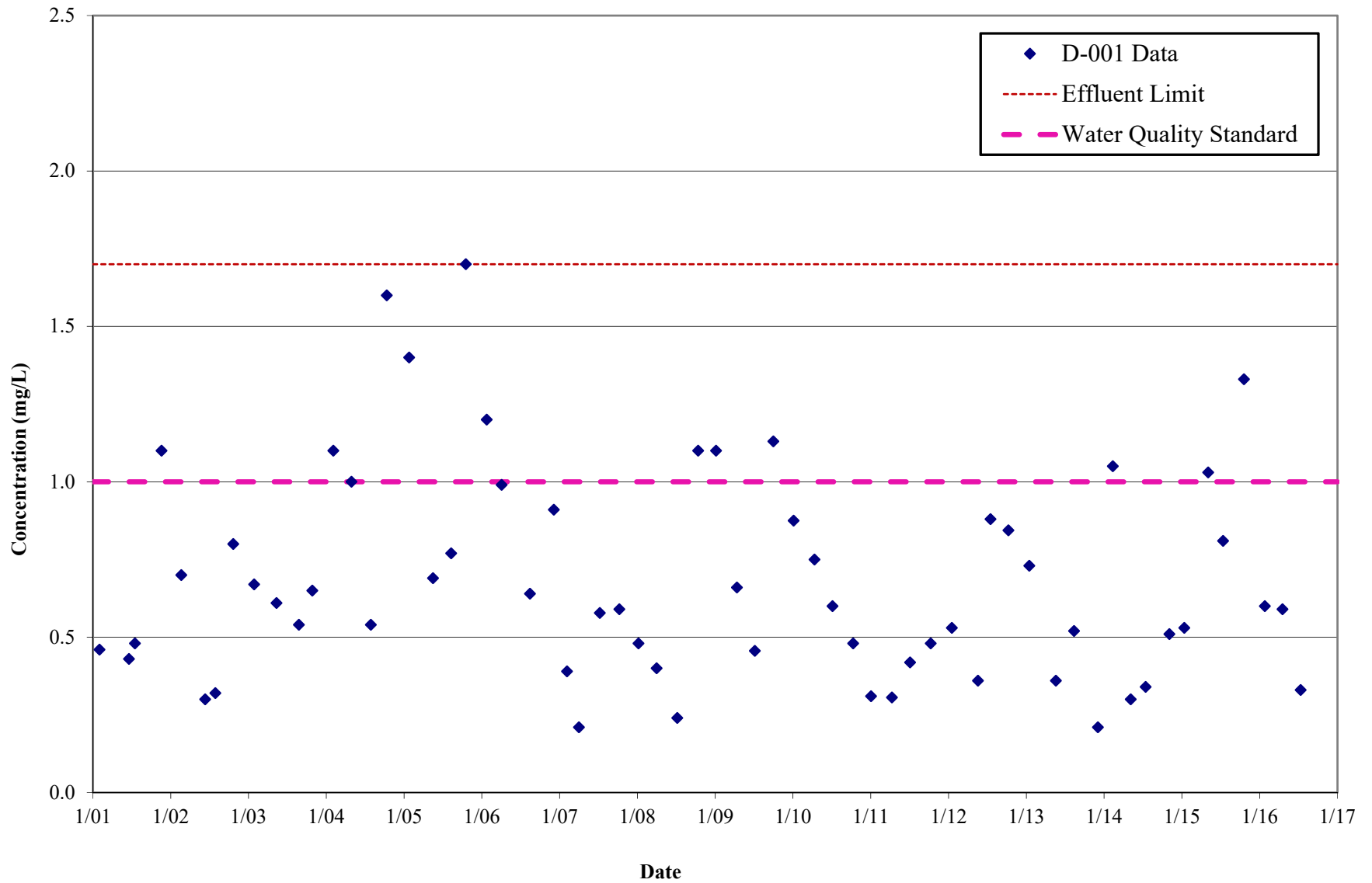


FIGURE 3-1.

IRON DATA AT OUTFALL D-001

Source: ECT, 2017.



3-4

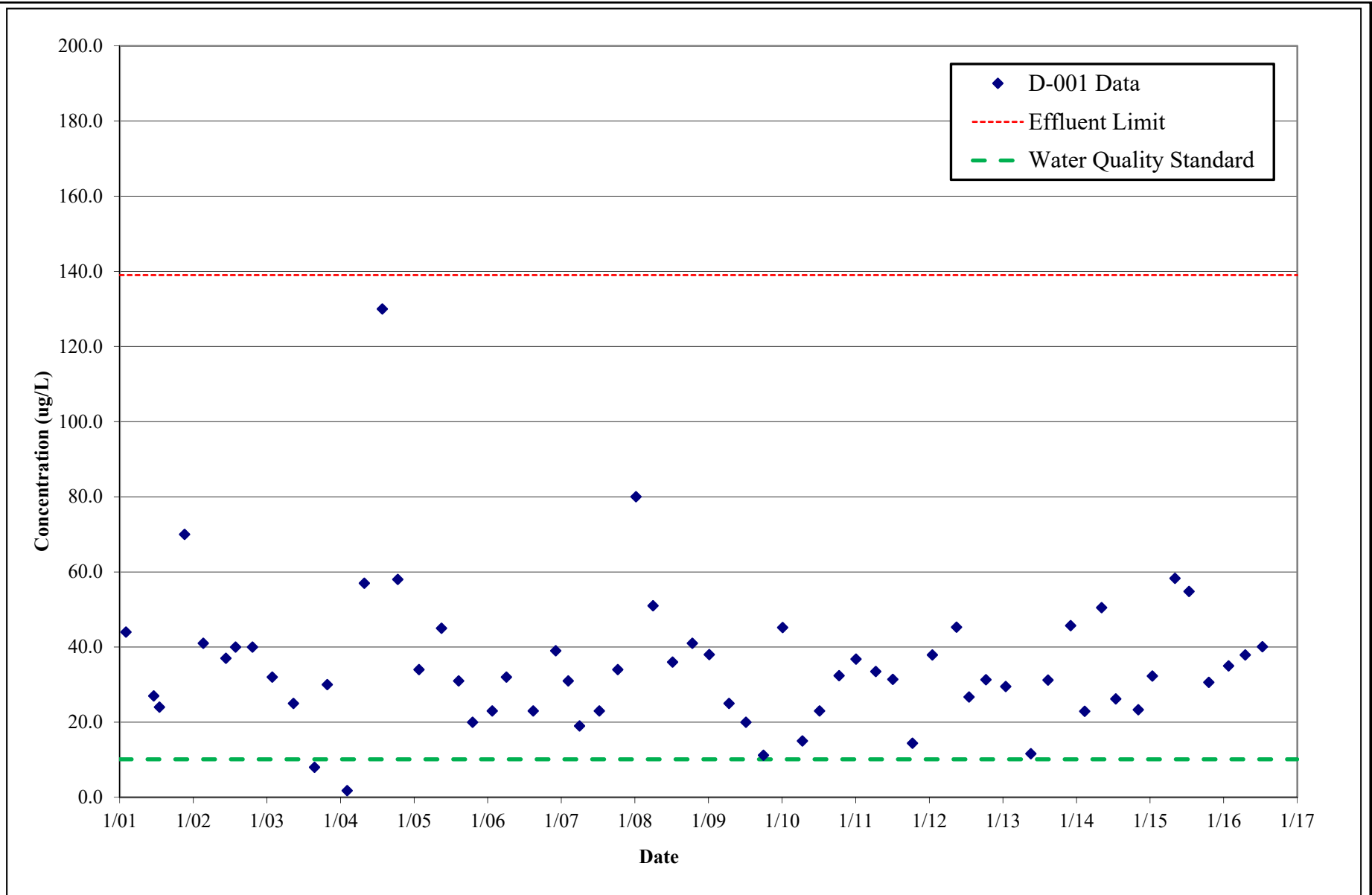


FIGURE 3-2.

COPPER DATA AT OUTFALL D-001

Source: ECT, 2017.



3-3

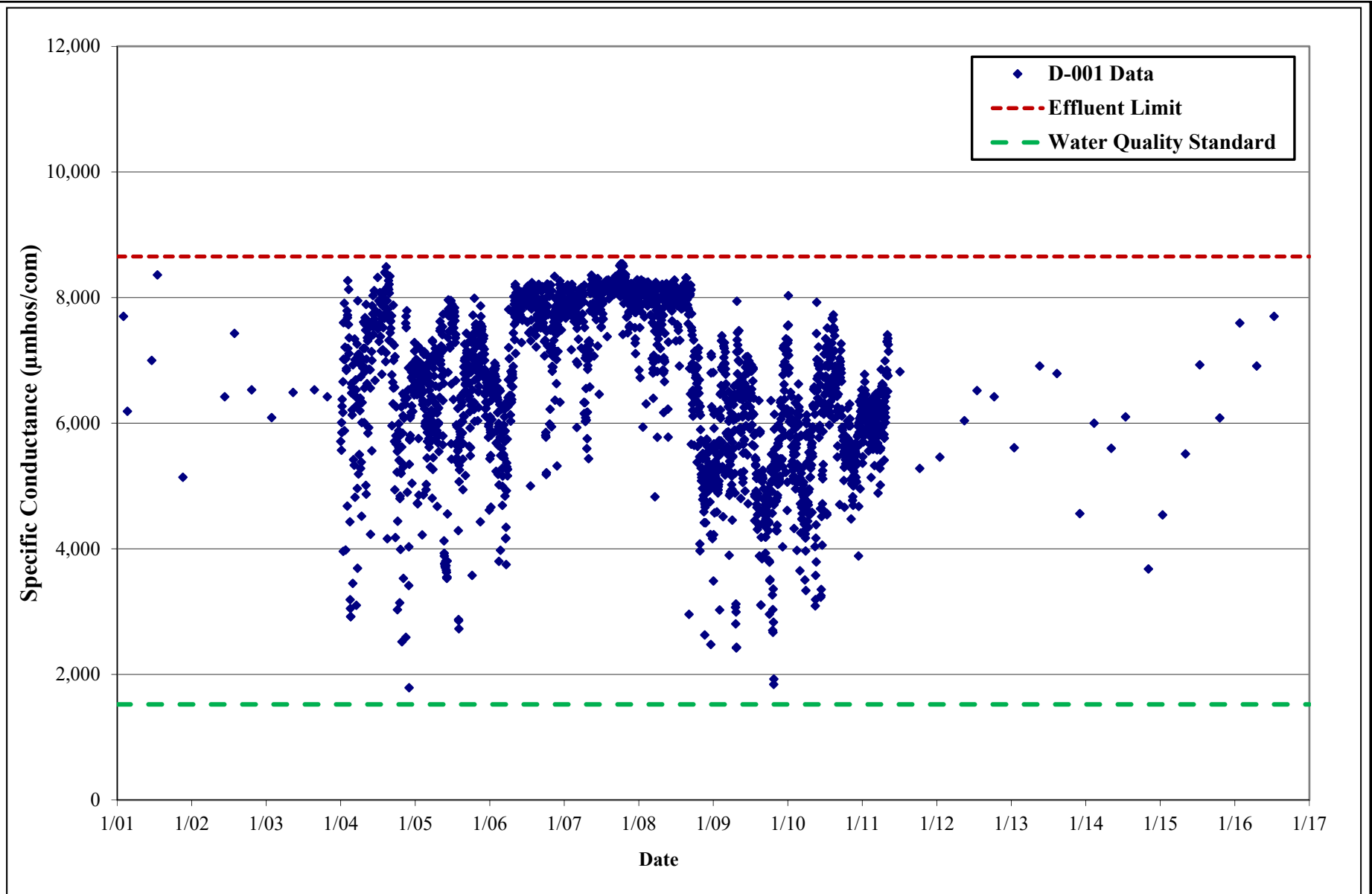


FIGURE 3-3.

SPECIFIC CONDUCTANCE DATA AT OUTFALL D-001

Source: ECT, 2017.



3.2.3 SPECIFIC CONDUCTANCE DATA

Figure 3-3 presents the specific conductance data at Outfall D-001 from 2001 to the present. The data indicate, since the last permit renewal, the specific conductance at D-001 was below the permit limit of 8,653 micromhos per centimeter ($\mu\text{mhos/cm}$). Table A-6 in Appendix A presents the specific conductance data values.

3.2.4 TOTAL CYANIDE DATA

Figure 3-4 presents the total cyanide data at Outfall D-001. The data indicate the total cyanide at D-001 has not exceeded the permit limit of 19.6 $\mu\text{g/L}$ during this permit cycle. Due to previous exceedances of cyanide and selenium limits in 2007 and 2008, FDEP reviewed the cyanide data and determined the results were inconclusive and did not provide an adequate basis for a determination of noncompliance. Consequently, FDEP issued an administrative order (AO) (No. 016TL) on December 14, 2006, with the following requirements:

- SECI shall complete studies to identify and evaluate potential cyanide and selenium sources within the SGS facility.
- No later than 24 months after the effective date of the AO, SECI shall either comply with the total cyanide and recoverable selenium discharge limitations specified in the NPDES permit or propose an alternative discharge limitation based on the cyanide and selenium studies.

On December 11, 2007, SECI submitted to FDEP a Phase I study report on its evaluation of the sources of cyanide and selenium, pursuant to AO 016TL. SECI also requested an extension of the deadline for compliance with total cyanide and total recoverable selenium discharge limitations. On November 24, 2008, FDEP issued a revision of AO 016TL that required the following:

- SECI shall complete a Phase II study for cyanide and selenium evaluation and submit a report no later than December 1, 2009.
- SECI shall either comply with the cyanide and selenium discharge limitations or with alternative discharge limitations no later than October 1, 2010, based on the results of the Phase II study.

3-7

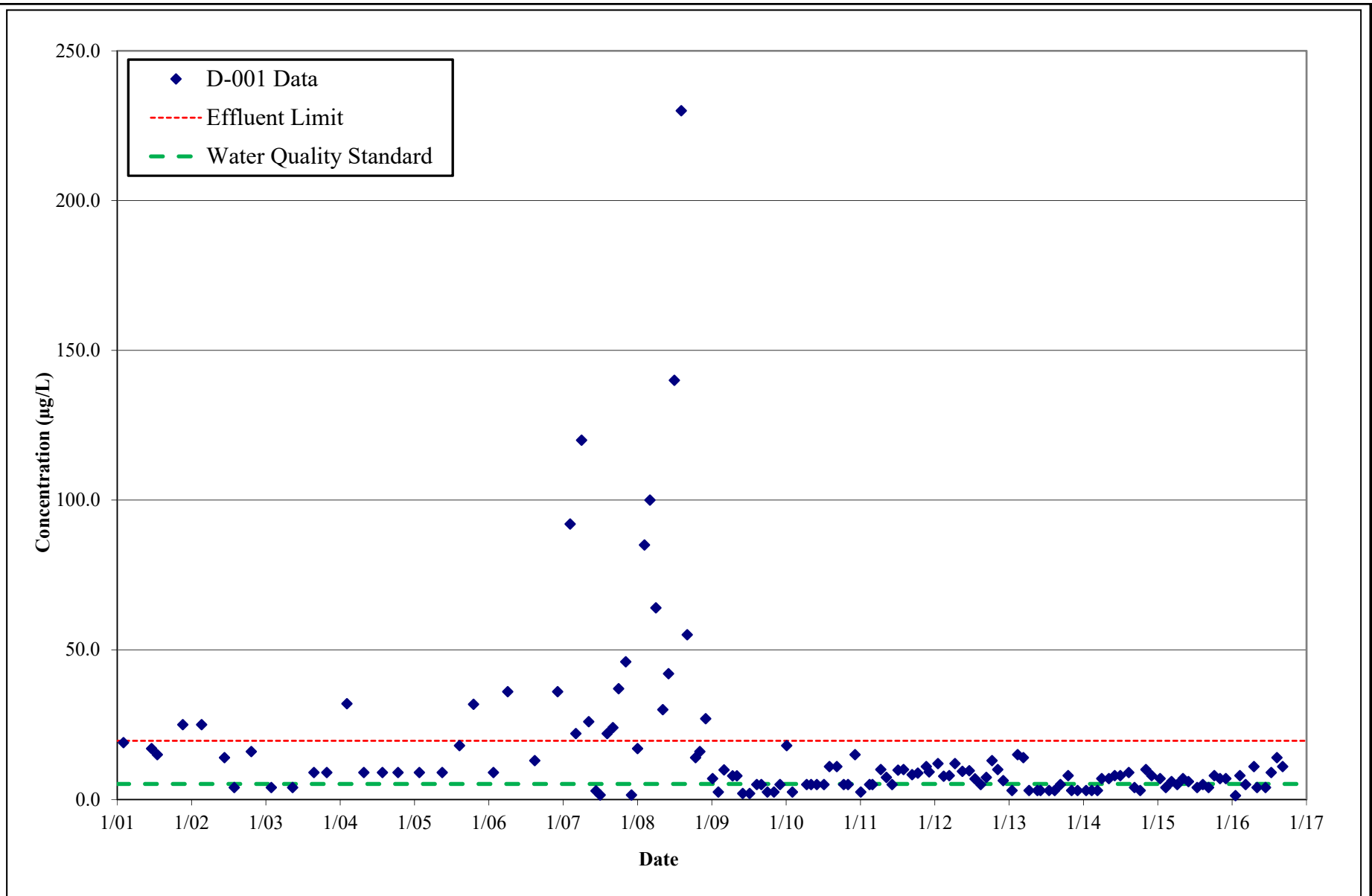


FIGURE 3-4.

CYANIDE DATA AT OUTFALL D-001

Source: ECT, 2017.



In November 2009, SECI completed the Phase II study as required by FDEP.

The Phase II study results showed the factors that contributed to the cyanide exceedances might have included the following:

- The analytical method for cyanide analysis (U.S. Environmental Protection Agency [EPA] Method 335) tends to produce large amounts of variability and often yields positively biased results.
- Hydrogen cyanide potentially was produced in the boiler due to incomplete combustion.

Because of the outcome of the Phase I and II studies, SECI made various improvements, the cyanide concentration dropped significantly, and cyanide effluent limit exceedance has not been reported since January 1, 2009.

Table A-3 in Appendix A presents the cyanide data values at Outfall D-001.

3.2.5 TOTAL RECOVERABLE SELENIUM DATA

Figure 3-5 presents the total recoverable selenium data at Outfall D-001 from 2001 to the present. The data indicate selenium concentration at D-001 have not exceeded the effluent limit of 11.7 µg/L during the current permit cycle. Previously, primarily in 2006 and early 2007, occasional selenium exceedances were reported. SECI has conducted and completed Phase I and II studies in accordance with the requirement by AO 016TL issued by FDEP. SECI has improved the treatment efficiency at the FGD wastewater treatment facility by increasing the gypsum purge rate. Since October 2007, selenium at Outfall D-001 has not exceeded the effluent limit. Table A-4 in Appendix A presents the selenium data values.

3.2.6 TOTAL RECOVERABLE MERCURY DATA

Figure 3-6 presents the total recoverable mercury data from 2001 to the present. The data indicate the mercury concentration at D-001 has generally decreased during the current permit with the exception of one outlier sample reported in September 2015 of 0.35 µg/L. This outlier was related to work being conducted on the FGD system and is not expected to be a recurring issue.

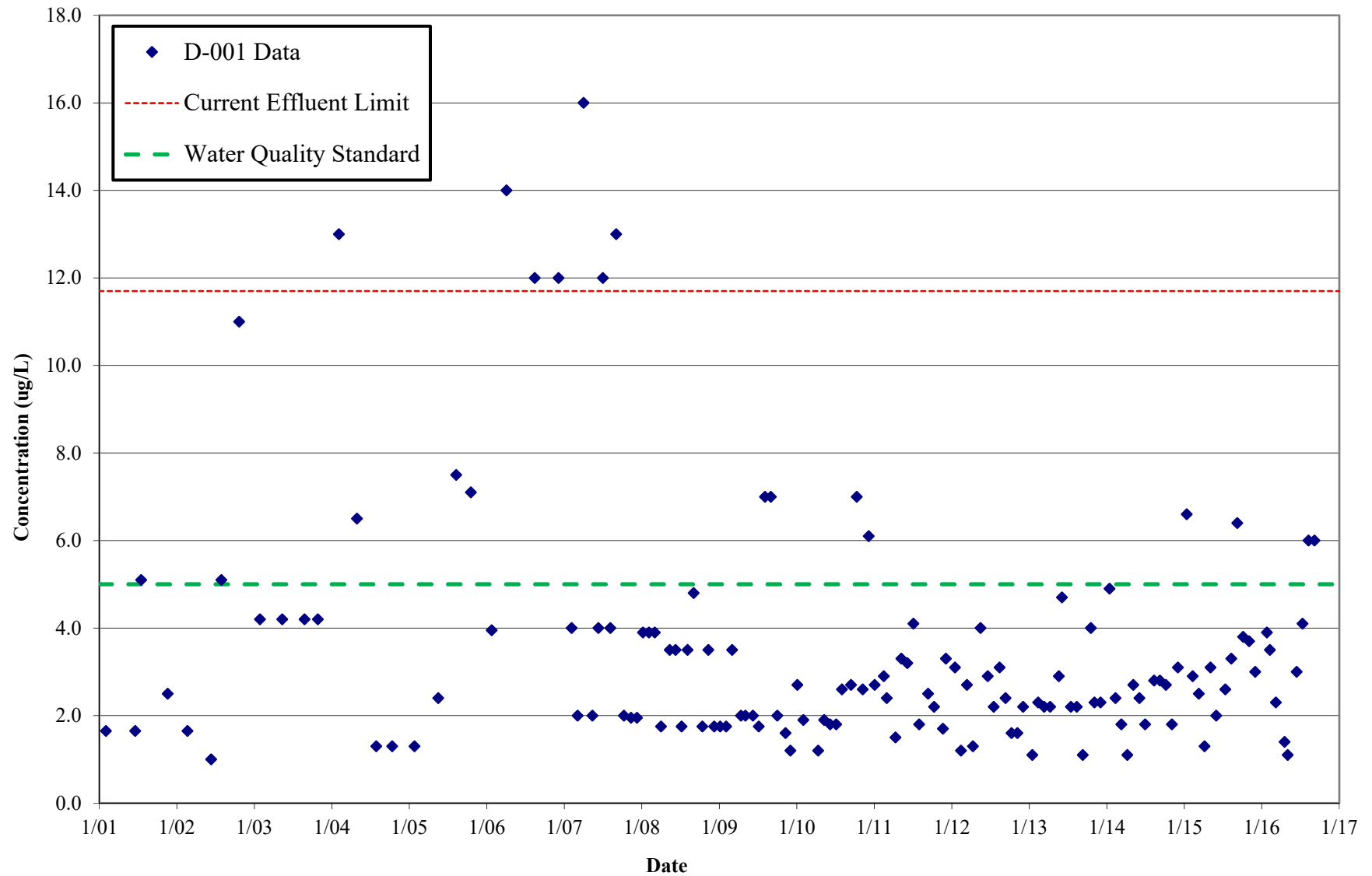


FIGURE 3-5.

SELENIUM DATA AT OUTFALL D-001

Source: ECT, 2017.



3-10

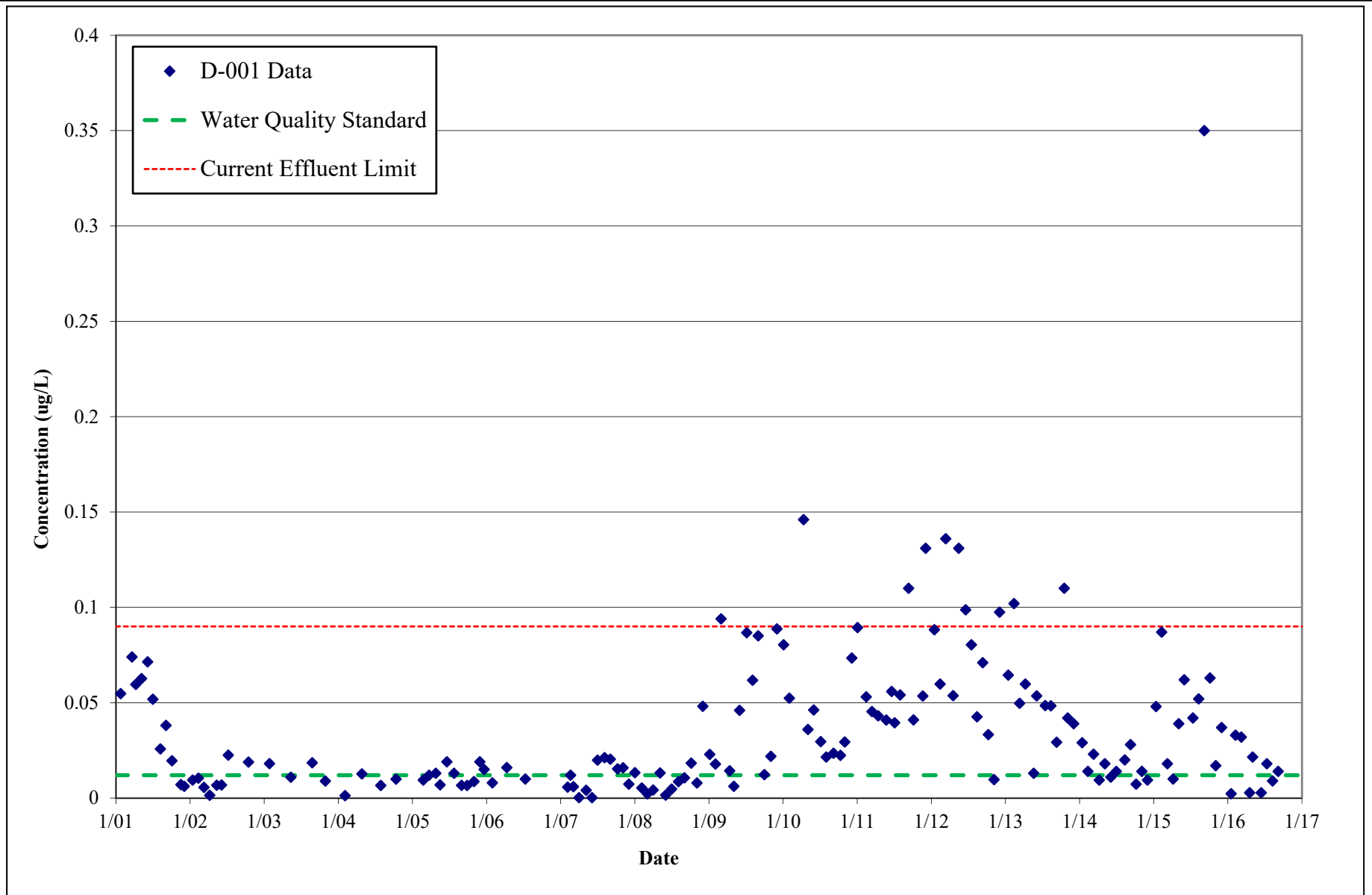


FIGURE 3-6.

MERCURY DATA AT OUTFALL D-001

Source: ECT, 2017.



Historical data presented during the previous permit indicated an increase since 2009, likely due to the operation of the recently installed SCR systems. With the exception of the September 2015 sample, the highest mercury concentration was 0.11 µg/L, exceeding the effluent limit of 0.09 µg/L. The SCR systems, although increasing the mercury load at Outfall D-001, reduce the emissions of mercury and consequently the atmospheric deposition of mercury on the St. Johns River and its watershed. Nitrogen deposition modeling conducted by TetraTech in 2007 has shown the selective catalytic reduction (SCR) results in a net reduction of nitrogen load to the St. Johns River. It is believed the SCR systems have similar effects on net mercury load reduction.

3.2.7 WATER TEMPERATURE

Figure 3-7 shows the daily water temperature at Outfalls D-001 and D-005 (or INT-1) from 2001 to November 2017. The data indicate the water temperature at Outfall D-001 never exceeded the effluent limit of 98.8 degrees Fahrenheit (°F). The maximum Outfall D-001 temperature was 95.4°F. The predicted maximum temperature from the proposed SCCF Project will be 95°F. Figure 3-8 presents the temperature difference between Outfalls D-001 and D-005, or delta-T.

The data show the maximum delta-T was 26.3°F in the winter dating back to 2001 and 22.9°F during the current permit. Figure 3-9 presents the monthly average temperatures at Outfalls D-001 and D-005. Figure 3-10 presents delta-T, which indicates the highest delta-T occurred in January. Table 3-2 presents the monthly statistics of water temperature at Outfalls D-001 and D-005.

3-12

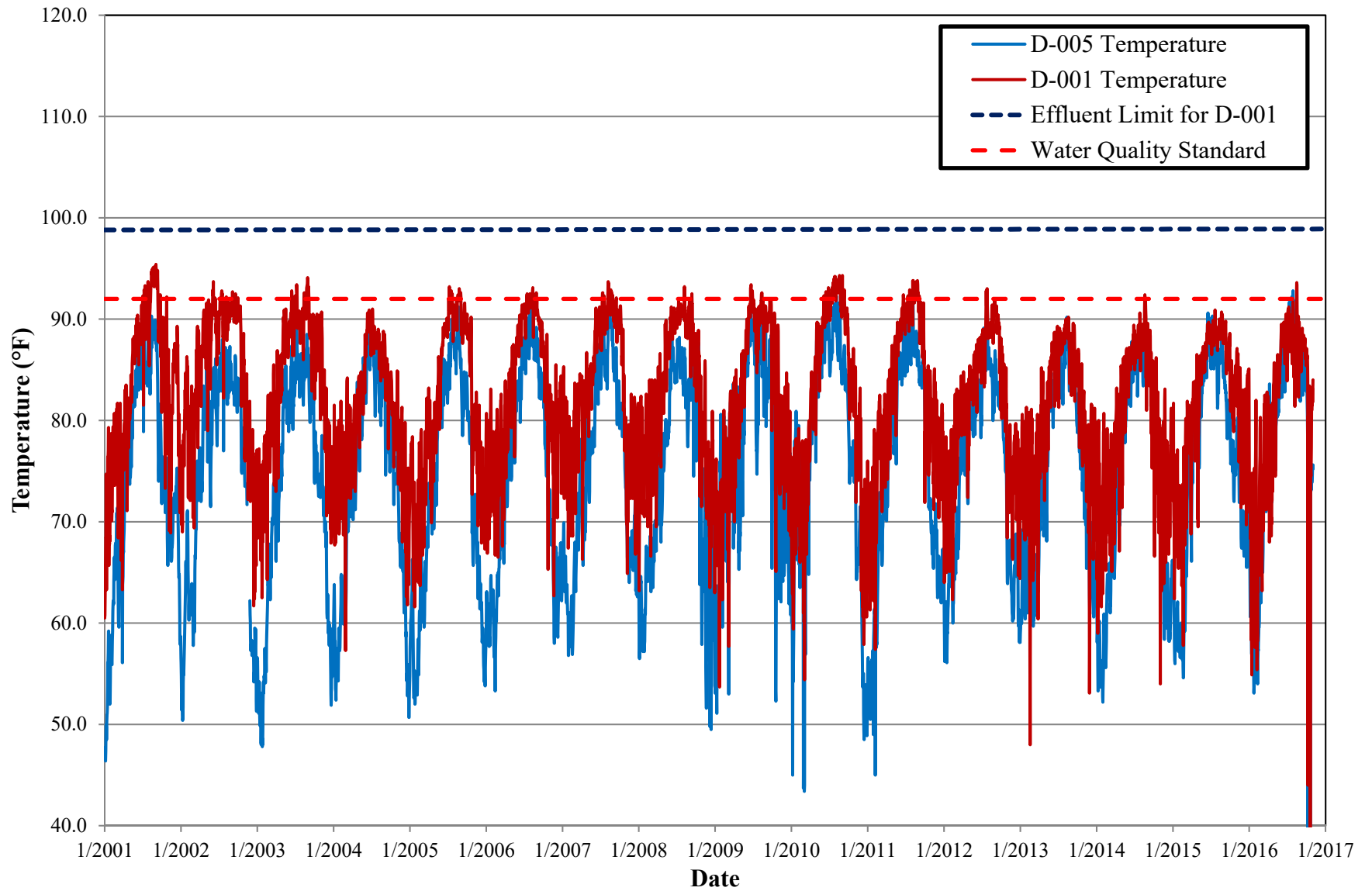


FIGURE 3-7.

DAILY WATER TEMPERATURE AT OUTFALLS D-001 AND D-005

Source: ECT, 2017.



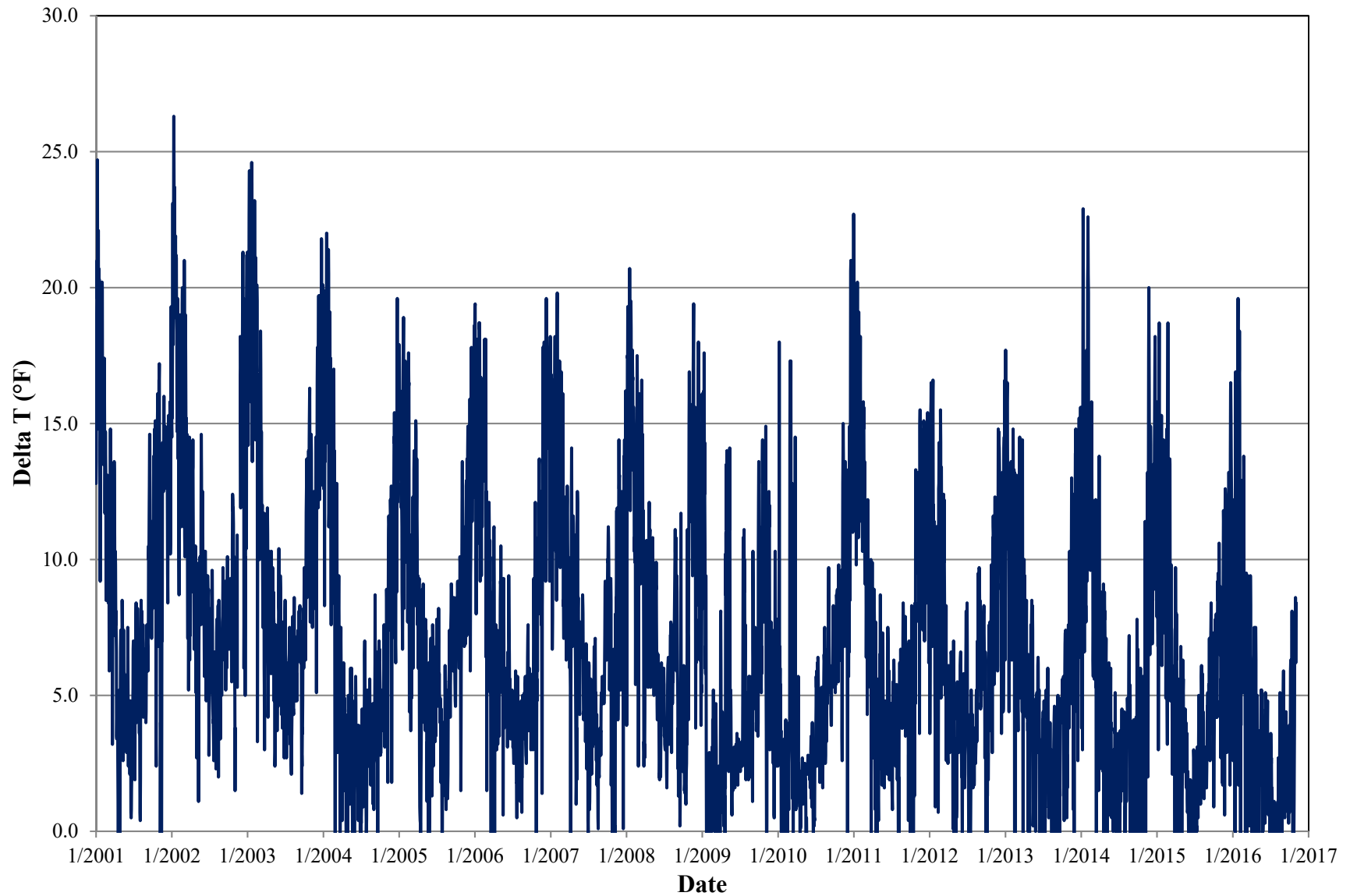


FIGURE 3-8.

DAILY DELTA-T BETWEEN OUTFALLS D-001 AND D-005

Source: ECT, 2017.



3-14

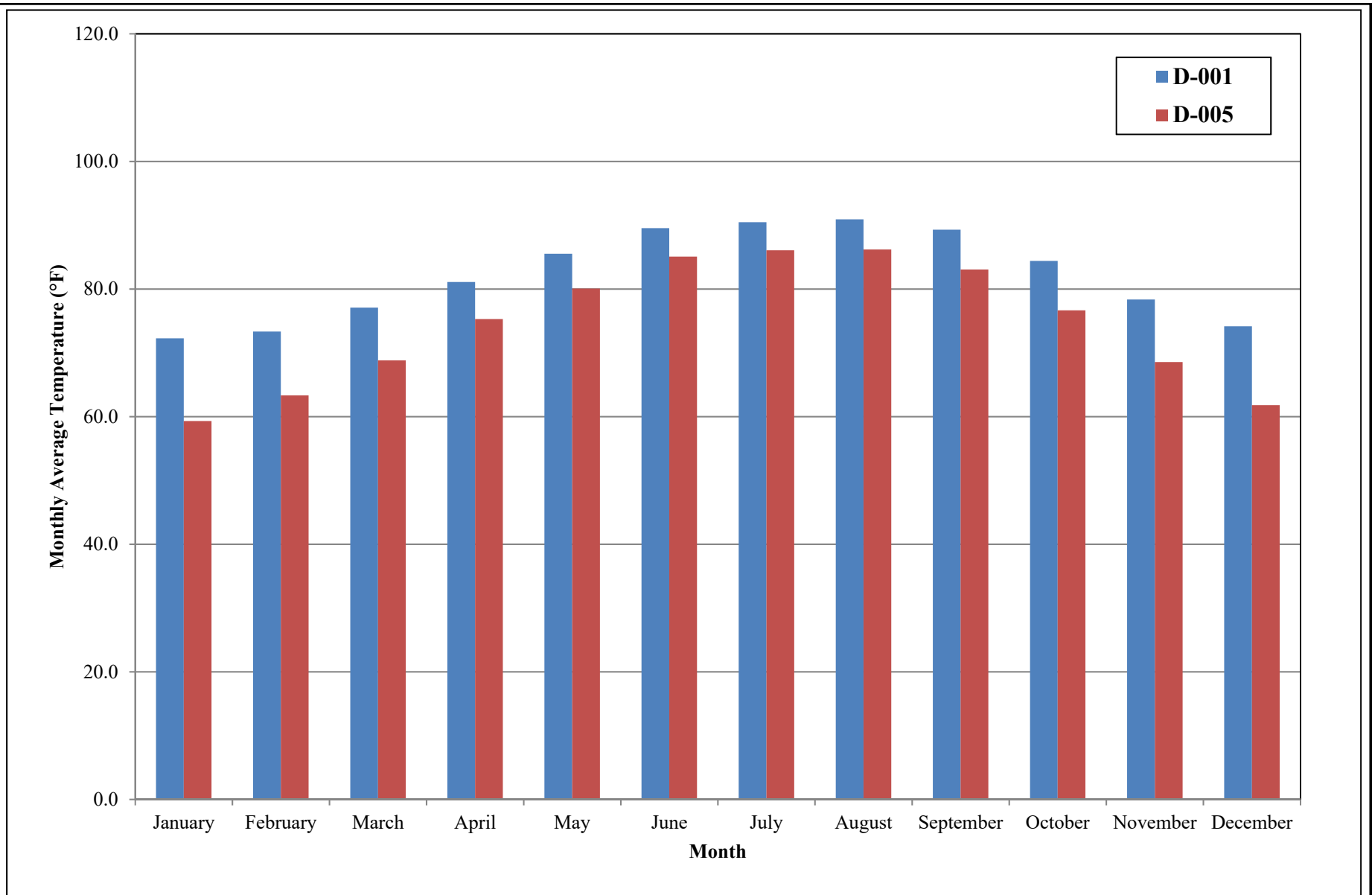


FIGURE 3-9.

MONTHLY AVERAGE TEMPERATURE AT OUTFALLS D-001 AND D-005

Source: ECT, 2017.



3-15

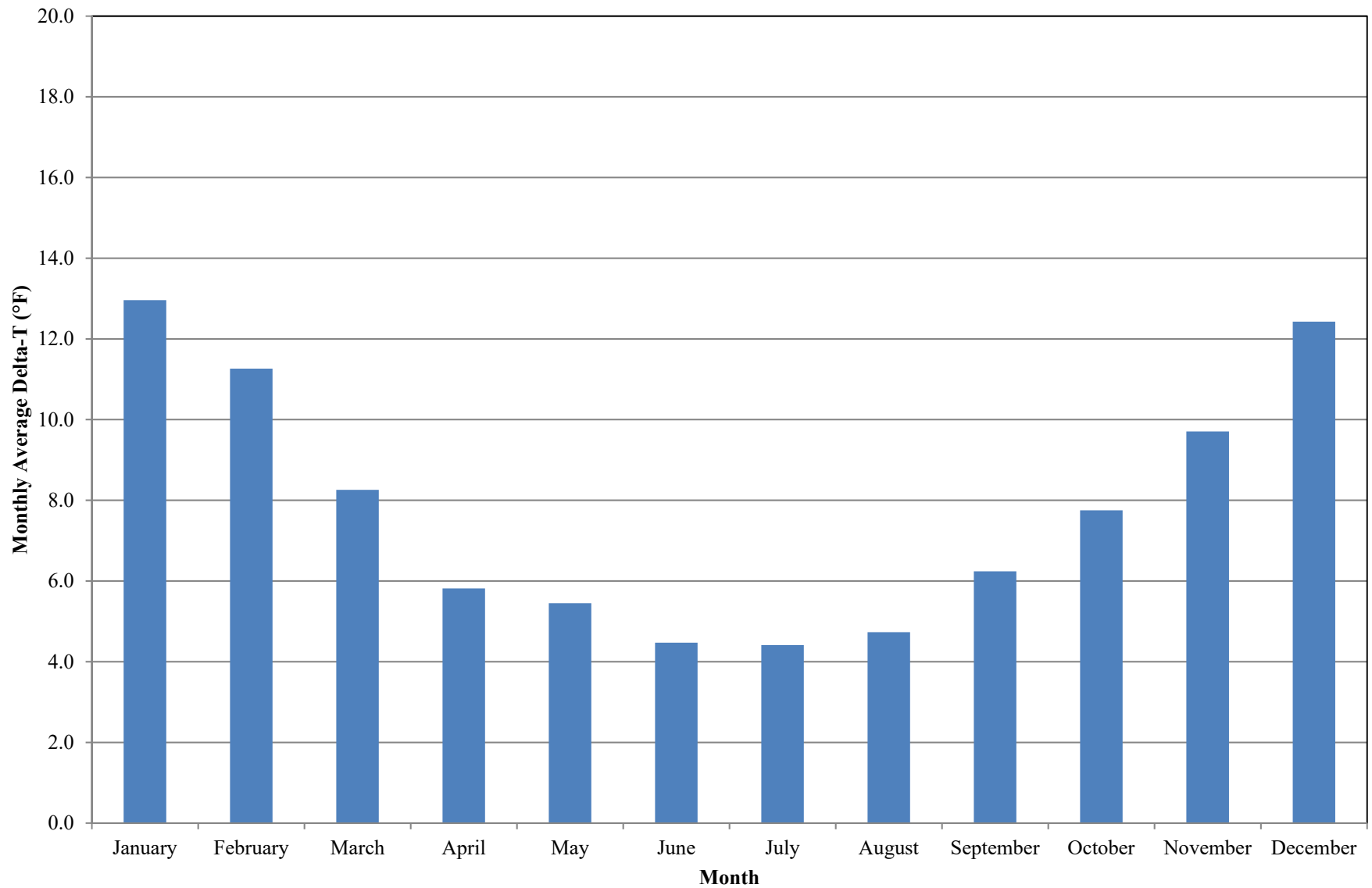


FIGURE 3-10.

MONTHLY AVERAGE DELTA-T

Source: ECT, 2017.



Table 3-2. Monthly Temperatures at Outfalls D-001 and D-005

	D-001 (°F)			D-005 (°F)			Delta-T (°F)	
	Maximum	Average	Minimum	Maximum	Average	Minimum	Maximum	Average
January	86.3	72.3	53.7	80.9	59.3	45.0	26.3	13.0
February	85.3	73.3	48.0	80.4	63.3	43.7	23.2	11.3
March	89.3	77.1	54.4	83.6	68.8	43.4	21.0	8.3
April	90.9	81.1	66.3	84.8	75.3	65.3	14.4	5.8
May	91.9	85.5	76.4	88.3	80.1	68.6	14.6	5.4
June	93.7	89.5	84.8	92.4	85.1	77.4	10.4	4.5
July	94.2	90.5	81.5	91.5	86.1	74.7	11.1	4.4
August	95.2	90.9	83.9	92.3	86.2	77.4	11.1	4.7
September	95.4	89.3	77.2	90.8	83.1	65.4	14.6	6.2
October	92.2	84.4	65.1	87.7	76.7	52.3	16.9	7.8
November	90.7	78.3	62.7	79.0	68.5	51.6	19.4	9.7
December	89.3	74.2	57.9	82.5	61.8	48.5	22.7	12.4

Source: ECT, 2017.

4.0 AMBIENT WATER QUALITY AND FLOW DATA

4.1 WATER QUALITY DATA

This section presents the ambient flow and water quality data in the St. Johns River for the parameters associated with the permitted or proposed mixing zones. The sources of the ambient water quality data included:

- SECI monitoring data at Intake INT-1, or D-005, in the St. Johns River.
- SECI ambient water quality study data.
- FDEP Impaired Water Rules data.
- The St. Johns River Water Management District.
- The U.S. Geological Survey (USGS).

Outfall D-001 is located in Water Body Identification (WBID) 2213L. Figure 4-1 shows the historic water quality monitoring stations in WBID 2213L.

Figure 4-2 shows the ambient total hardness data in WBID 2213L of the St. Johns River from 1993 through 2011. The average ambient hardness was 213.6 mg/L. Being conservative, the 5th percentile of the ambient total hardness (110 mg/L) was used to compute the following hardness-related water quality standard:

<u>Parameter</u>	<u>Water Quality Standard (µg/L)</u>
Cadmium	0.29
Chromium (trivalent)	93.2
Copper	10.1
Lead	3.59
Nickel	56.5
Zinc	129.9

Any nondetect water quality samples with MDLs greater than the water quality standard were not used for this study.

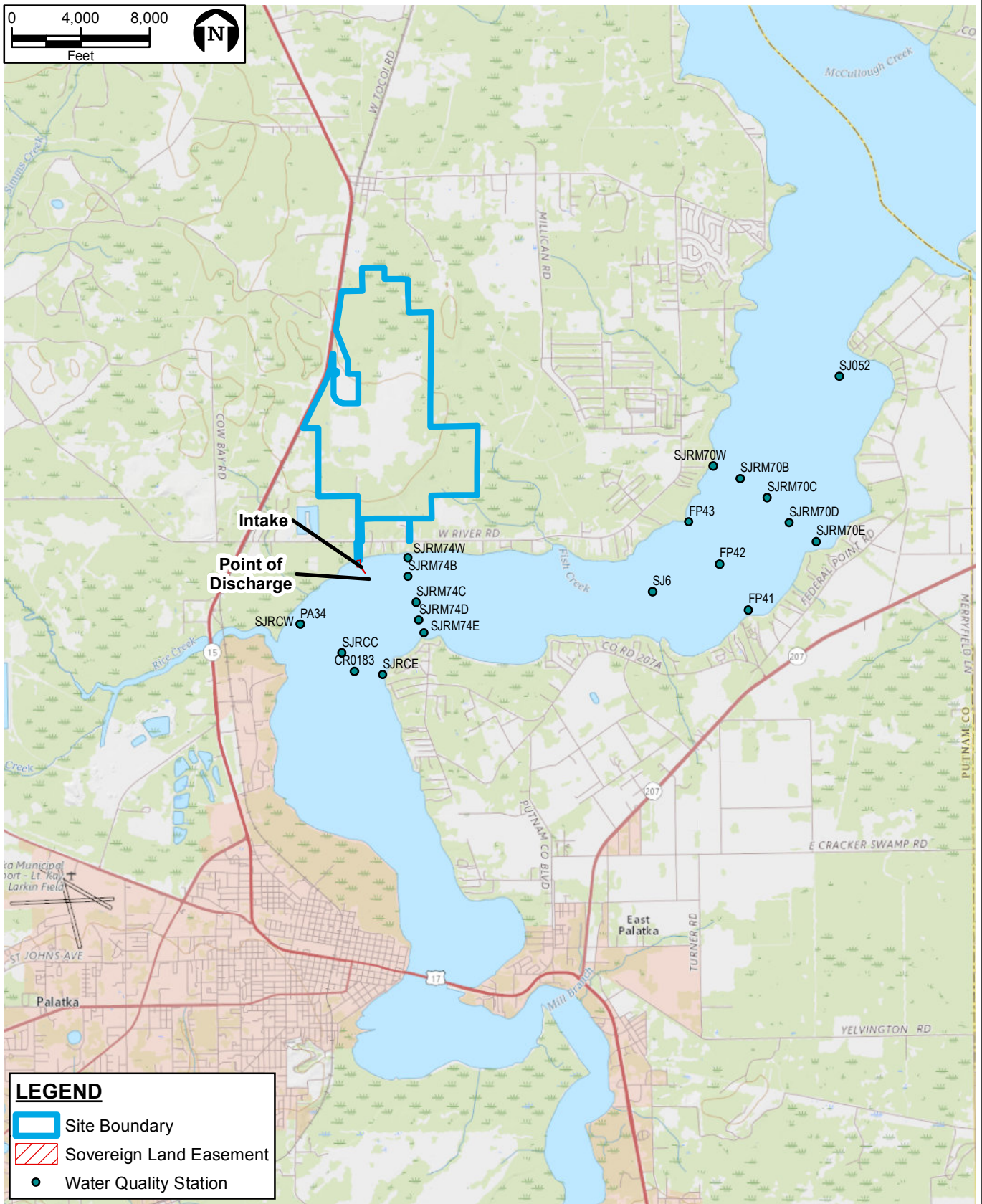


FIGURE 4-1.
WATER QUALITY MONITORING STATIONS IN WBID 2213L
IN VICINITY OF SGS SITE

Sources: USGS, 2016; SJRWMD, 2004; ECT, 2017.



4-3

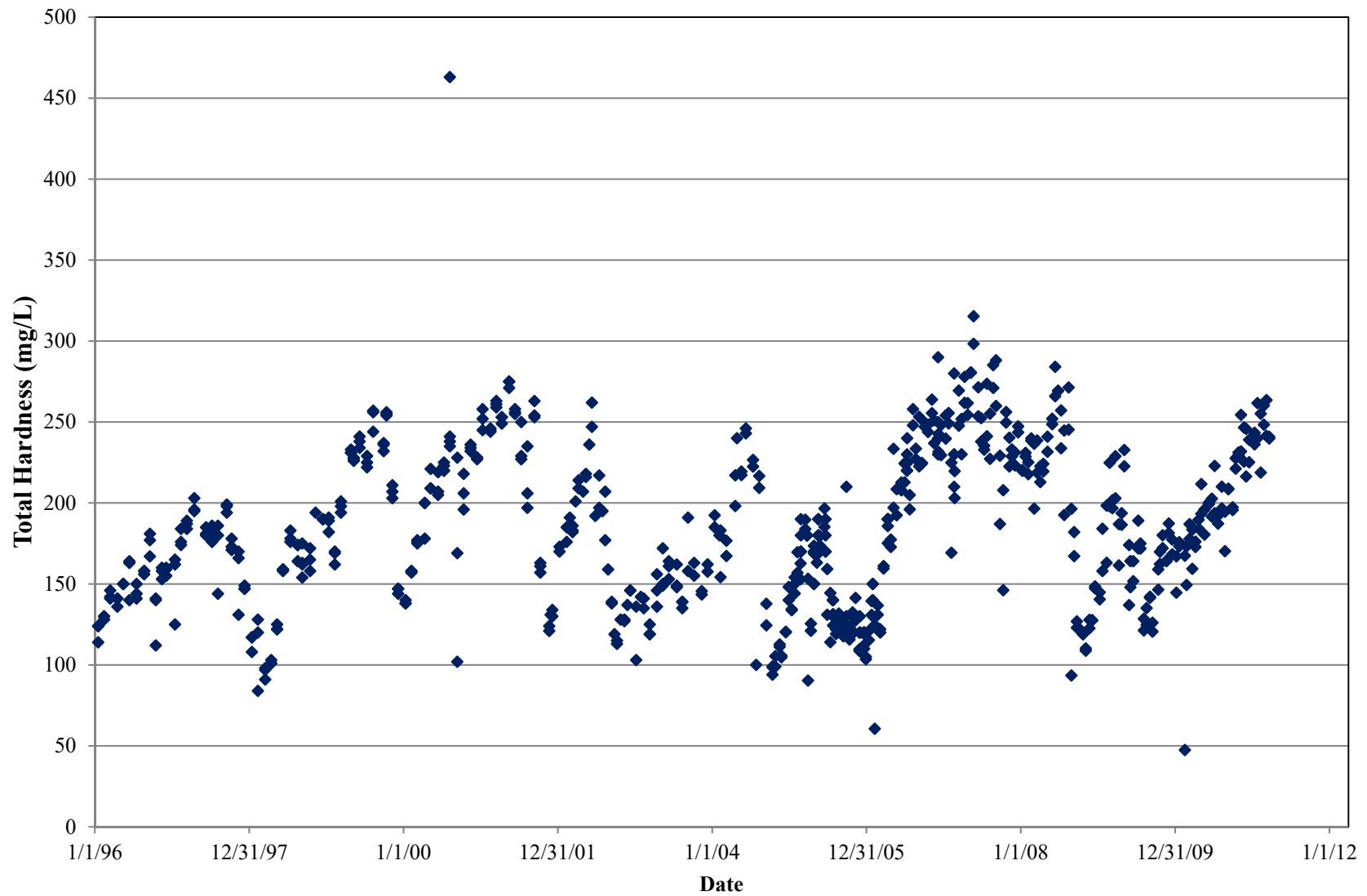


FIGURE 4-2.

AMBIENT TOTAL HARDNESS DATA IN WBID 2213L

Source: ECT, 2011.



Figures 4-3 through 4-9 present the ambient total recoverable iron, copper, specific conductance, total cyanide, selenium, mercury, and water temperature data, respectively. Table 4-1 summarizes the ambient water quality data. Appendix A contains the ambient water quality data.

4.2 AMBIENT FLOWS AND CURRENTS

USGS maintained a surface water gauging station at the St. Johns River at Palatka (USGS Station 2244450) from January 1, 1973, through September 30, 1982. The data indicated the St. Johns River at Palatka was influenced by tidal fluctuation and experienced periodic reversal of daily net flow direction. To determine the high- and low-flow conditions in the river, a frequency analysis was conducted for the magnitude of the daily average flow data during the 10-year period. Figure 4-10 shows the frequency curve for the daily average flow. The results indicated the 10th percentile low flow was 914 cubic feet per second (cfs), the 90th percentile high flow was 13,000 cfs, and the median daily flow was 5,040 cfs. Based on a river width of 6,000' and average depth of 10', the high-flow ambient current speed (90th percentile), based on net river flow, at the St. Johns River near SGS was approximately 0.22 foot per second (fps); the low-flow ambient current speed (10th percentile), based on net river flow, was approximately 0.015 fps; and the median daily flow velocity, based on net river flow, was 0.084 fps.

The data presented previously were based on daily average flows. The St. Johns River near SGS is under the influence of tidal current, which is much higher than the daily average flows. To quantify the tidal current velocity in the St. Johns River near Outfall D-001, ECT conducted a current study for two tidal cycles during a neap tide on September 26 and 27, 2005. A Nortek AquaDopp™ acoustic Doppler current profiler was deployed at the river bottom approximately 400' upstream of Outfall D-001 to avoid the hydrodynamic influence of the discharge jet/plume. Instantaneous current speed and direction at ten vertical levels were recorded continuously. Figure 4-11 shows the time series data of vertically averaged current speed. Table 4-2 shows the high, median, and low tidal current velocity for flood and ebb tides based on frequency analysis of the tidal current data. Tidal current data analysis indicated that the 90th percentile ebb current velocity (0.67 fps) is

4-5

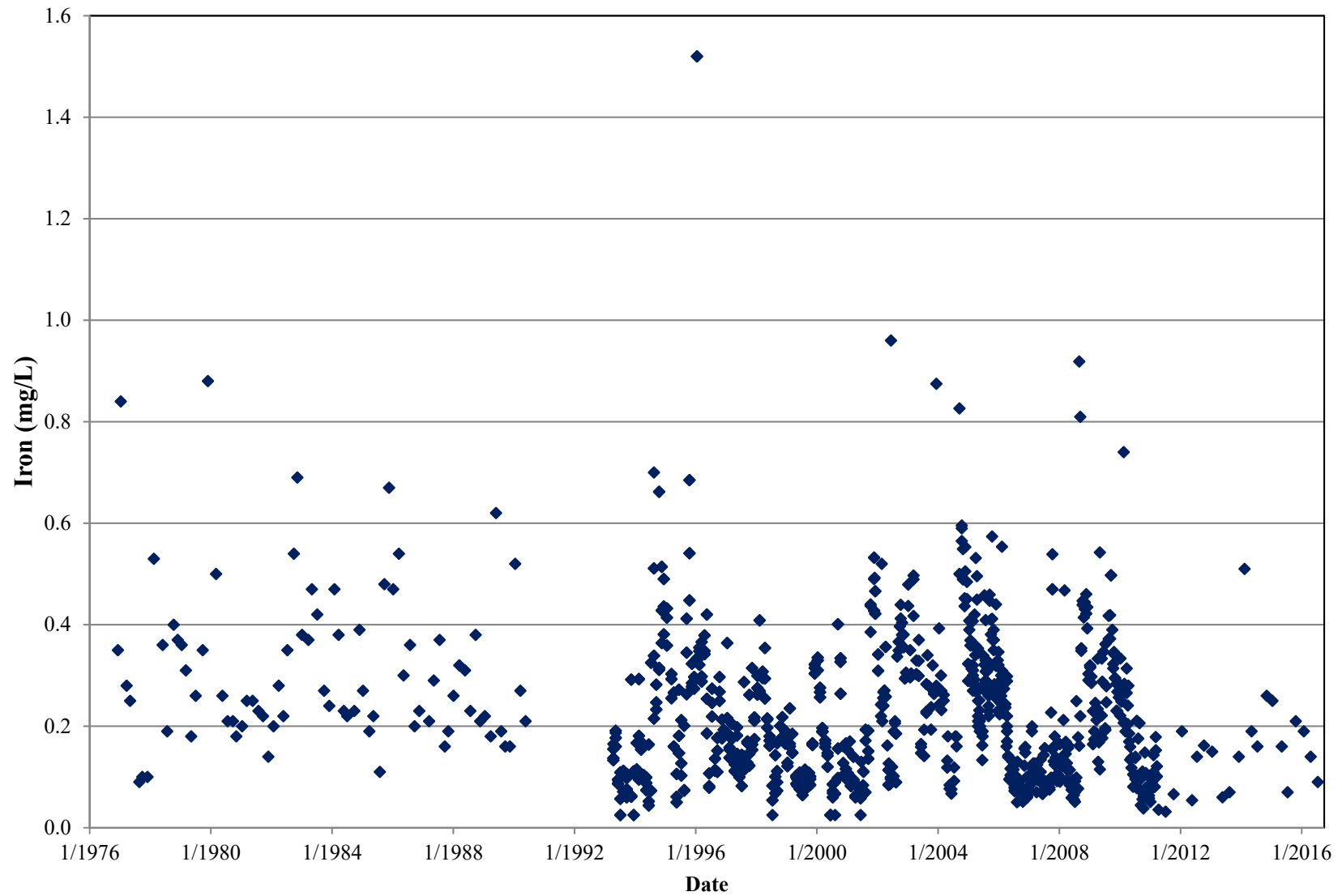


FIGURE 4-3.

AMBIENT IRON DATA IN WBID 2213L

Source: ECT, 2017.



4-6

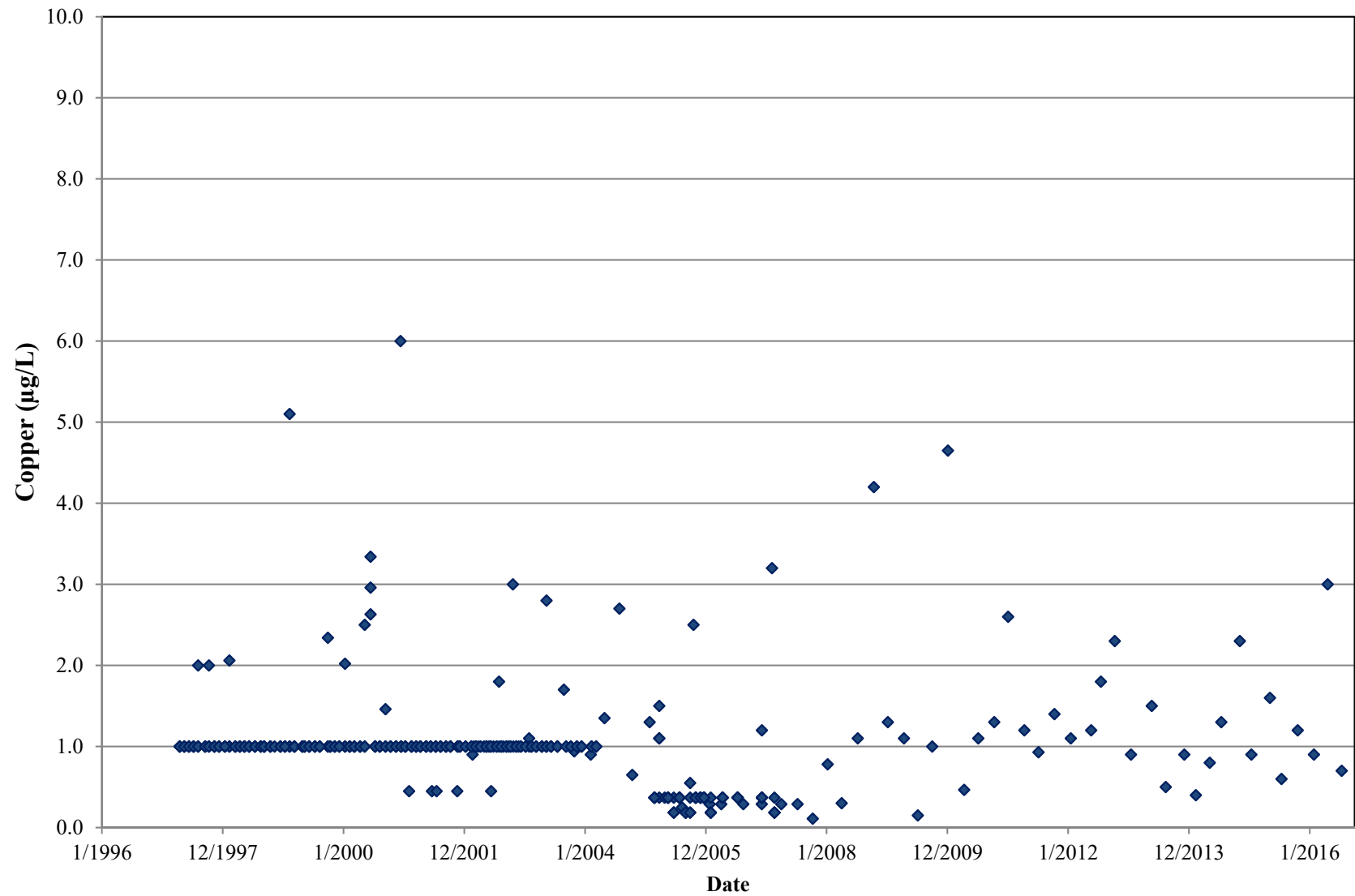


FIGURE 4-4.

AMBIENT COPPER DATA IN WBID 2213L

Source: ECT, 2017.



4-7

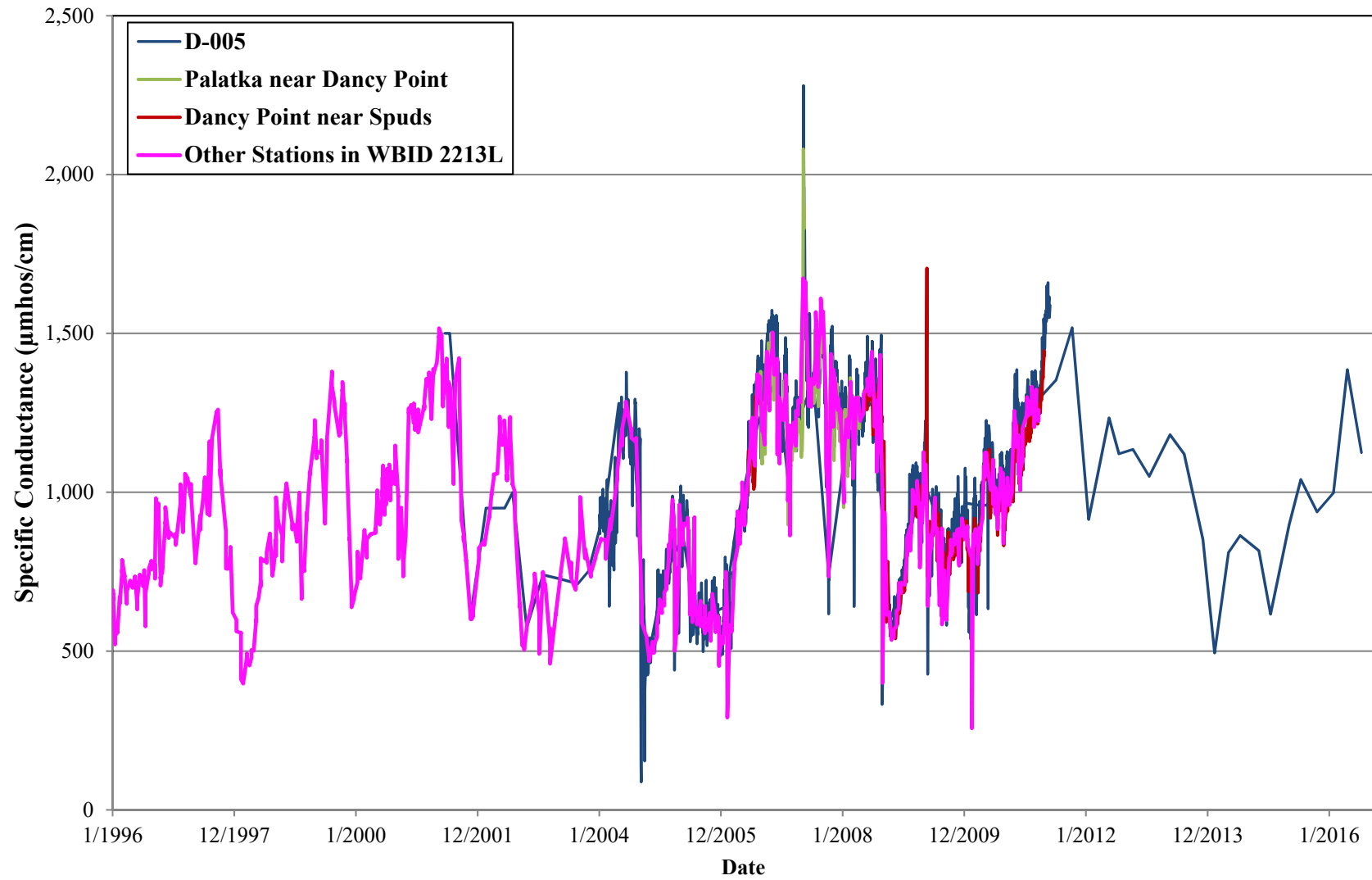


FIGURE 4-5.

AMBIENT SPECIFIC CONDUCTANCE DATA IN WBID 2213L

Source: ECT, 2017.

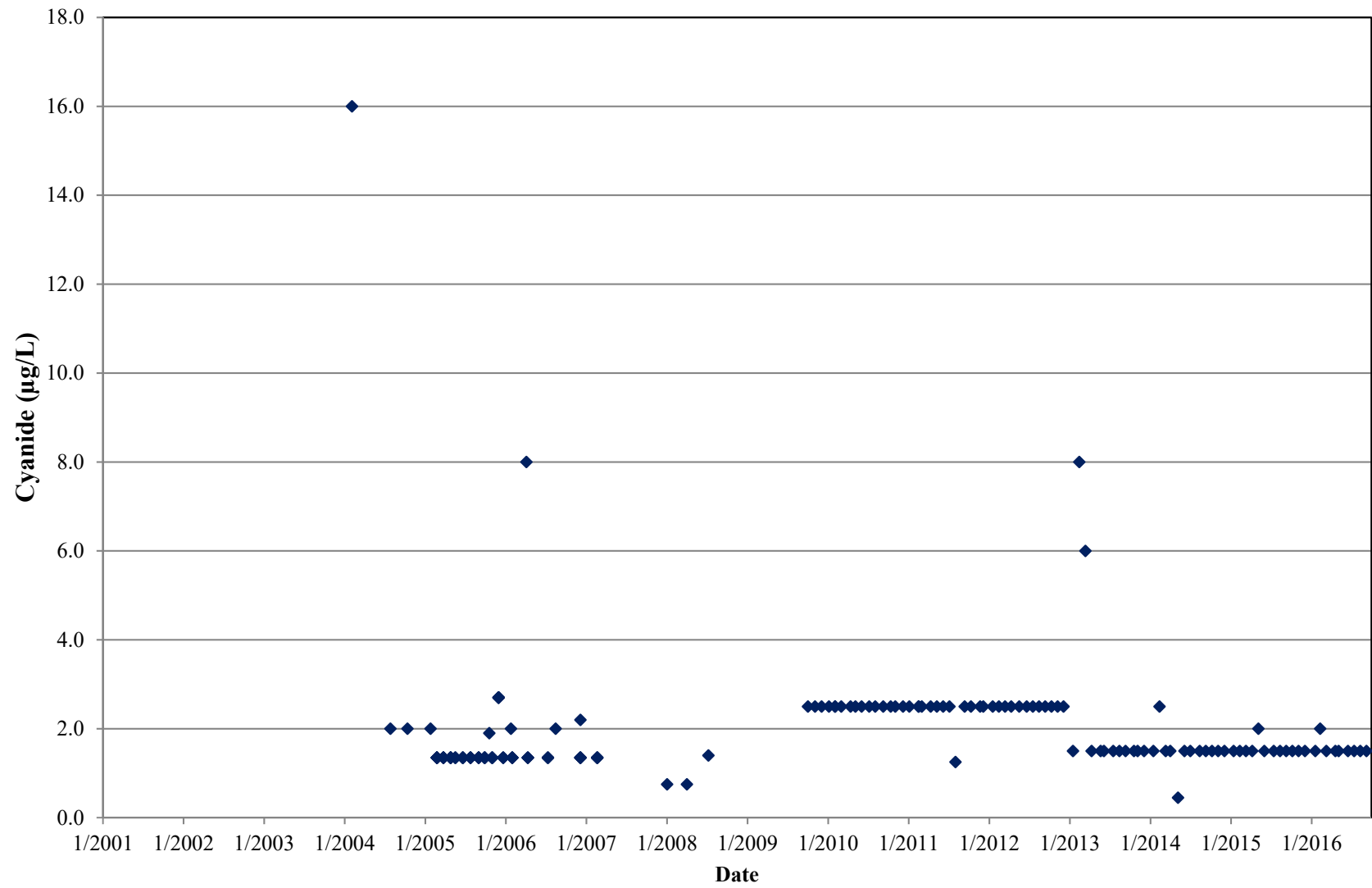


FIGURE 4-6.

AMBIENT CYANIDE DATA IN WBID 2213L

Source: ECT, 2017.



4-9

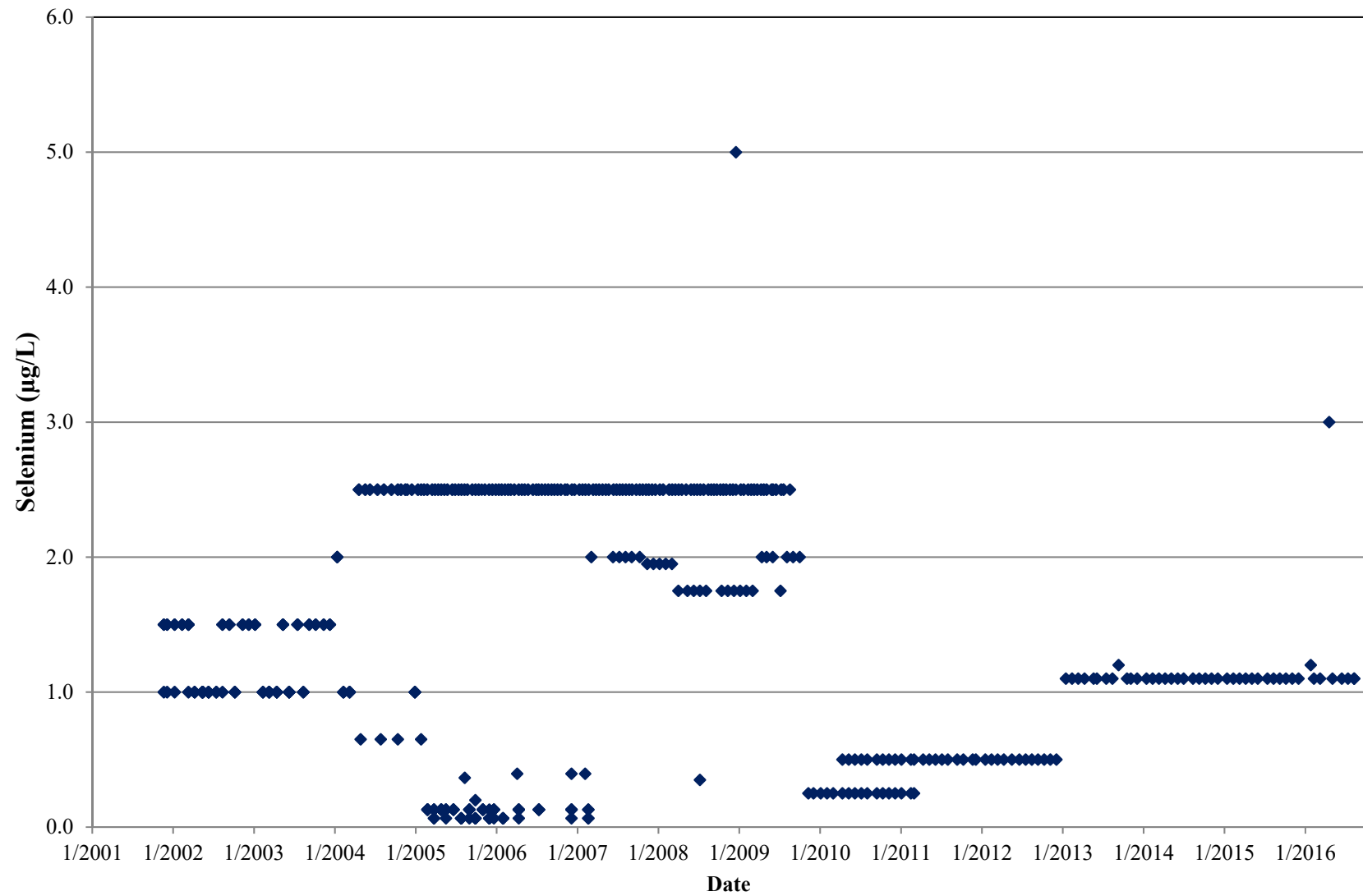


FIGURE 4-7.

AMBIENT SELENIUM DATA IN WBID 2213L

Source: ECT, 2017.



4-10

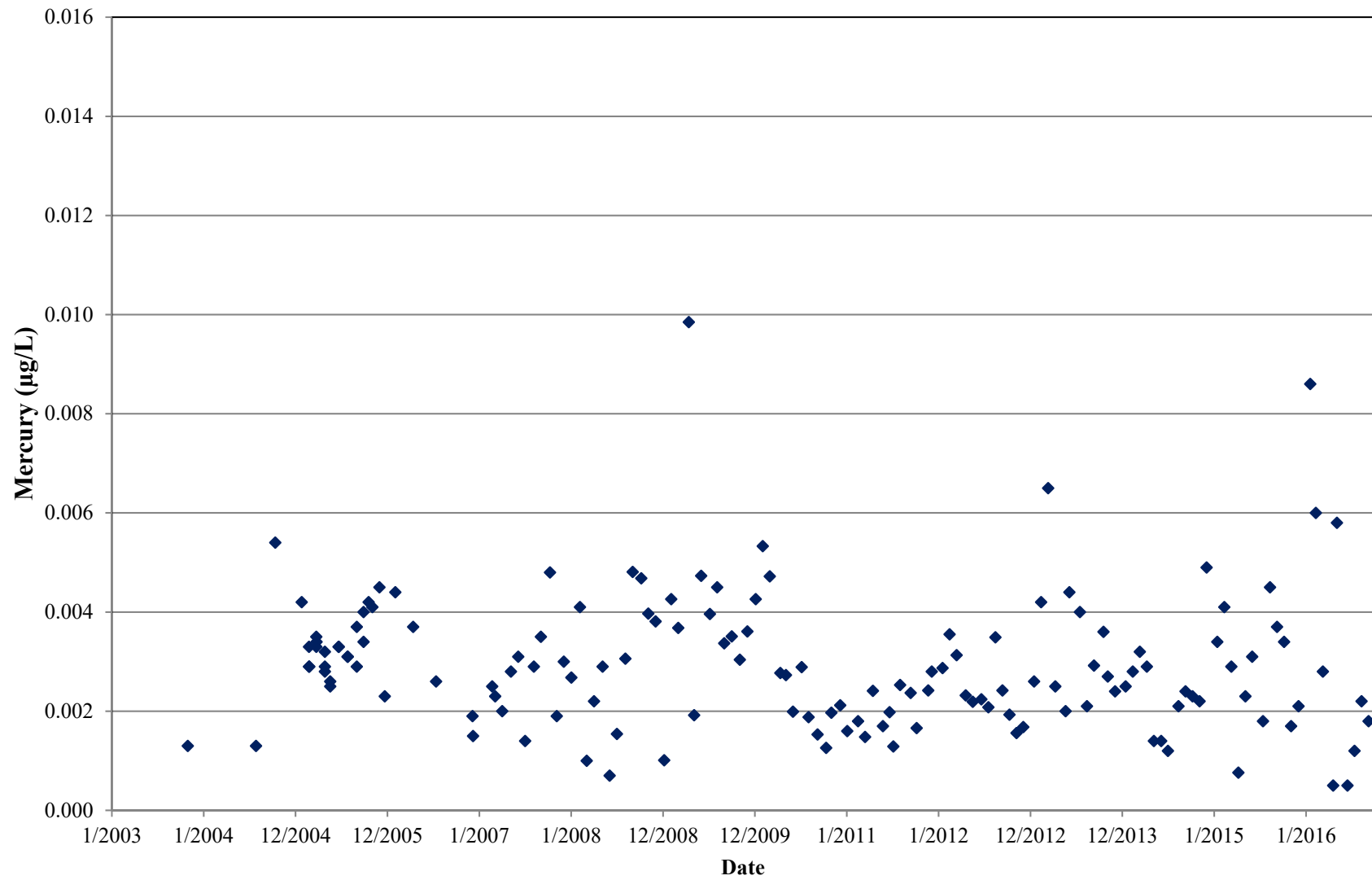


FIGURE 4-8.

AMBIENT MERCURY DATA IN WBID 2213L

Source: ECT, 2017.



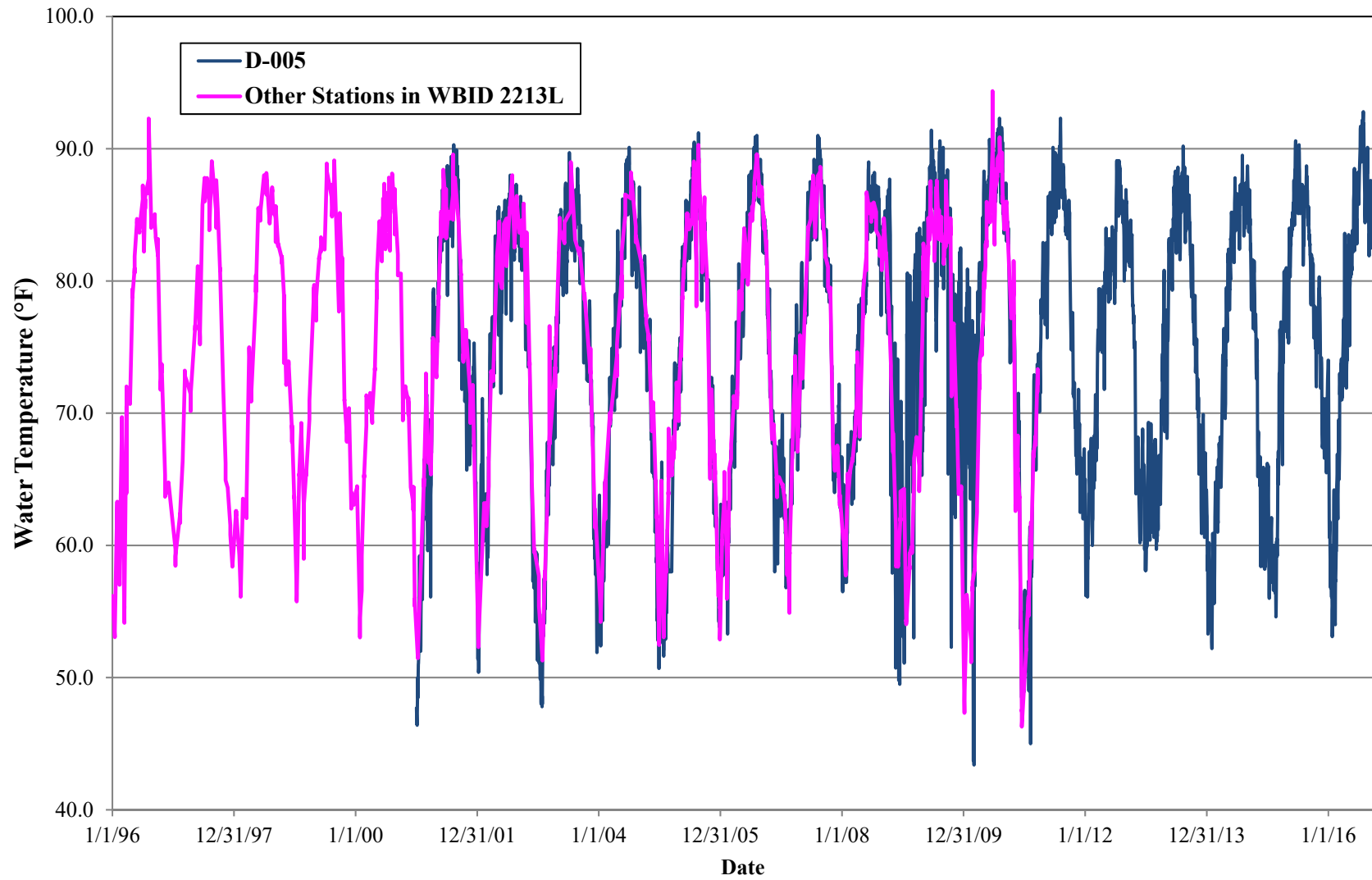


FIGURE 4-9.

AMBIENT WATER TEMPERATURE IN WBID 2213L

Source: ECT, 2017.



Table 4-1. Ambient Water Quality Data Summary

Parameter	Unit	Average	95 th Percentile	Water Quality Standard
Copper	µg/L	1.00	2.07	10.1
Cyanide	µg/L	1.94	2.70	5.2
Specific conductance	µmhos/cm	1,015	1,420	2,130*
Water temperature	°F	74.83	88.2	—
Iron	mg/L	0.22	0.47	1.0
Mercury	µg/L	0.00293	0.0047	0.012
Selenium	µg/L	1.70	2.5	5.0

*Water quality standard for specific conductance is 1.5 times the ambient value.

Source: ECT, 2017.

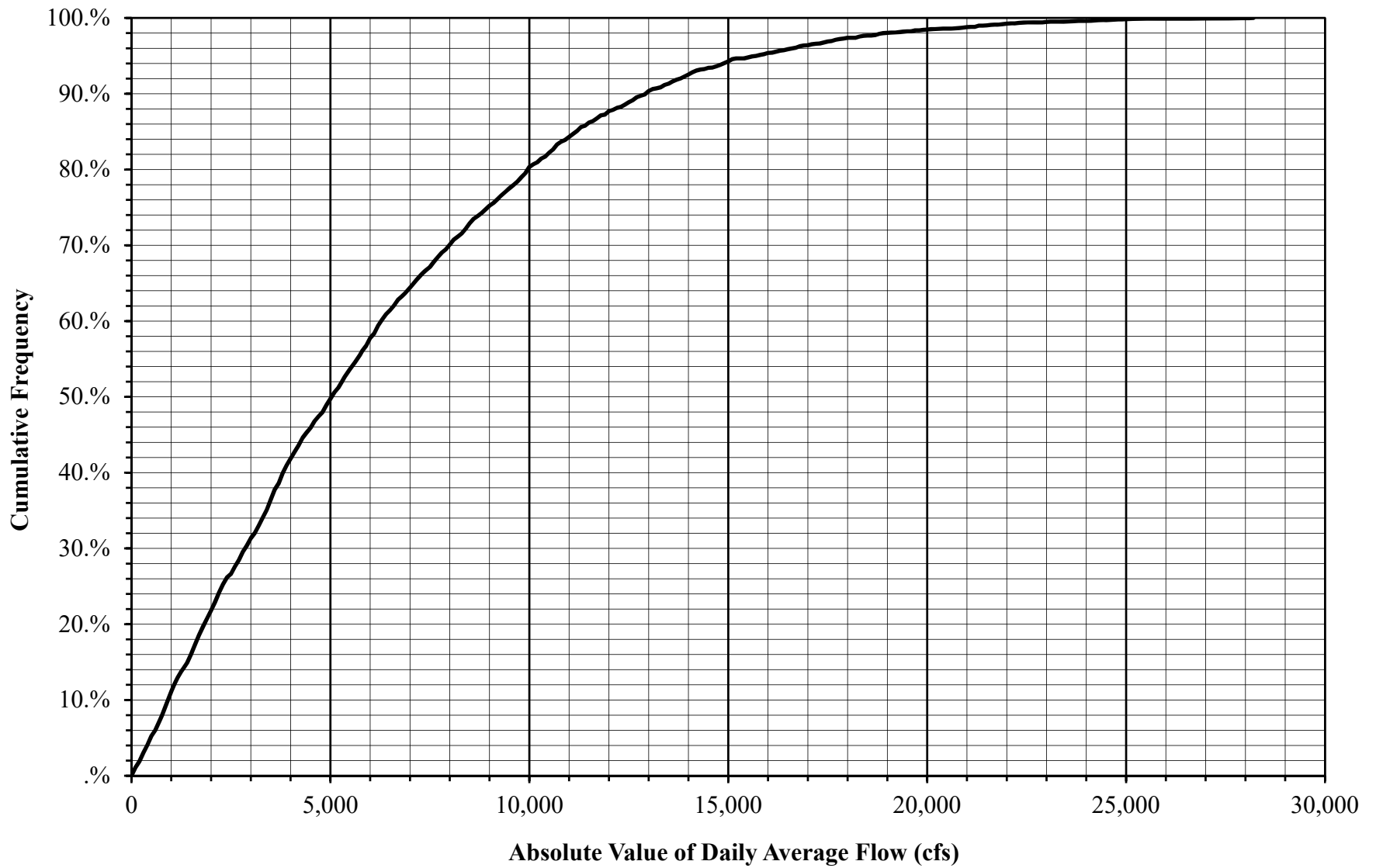


FIGURE 4-10.

FREQUENCY ANALYSES OF THE ST. JOHNS RIVER DAILY FLOW AVERAGE
AT PALATKA (1973 TO 1982)

Source: ECT, 2007.



4-14

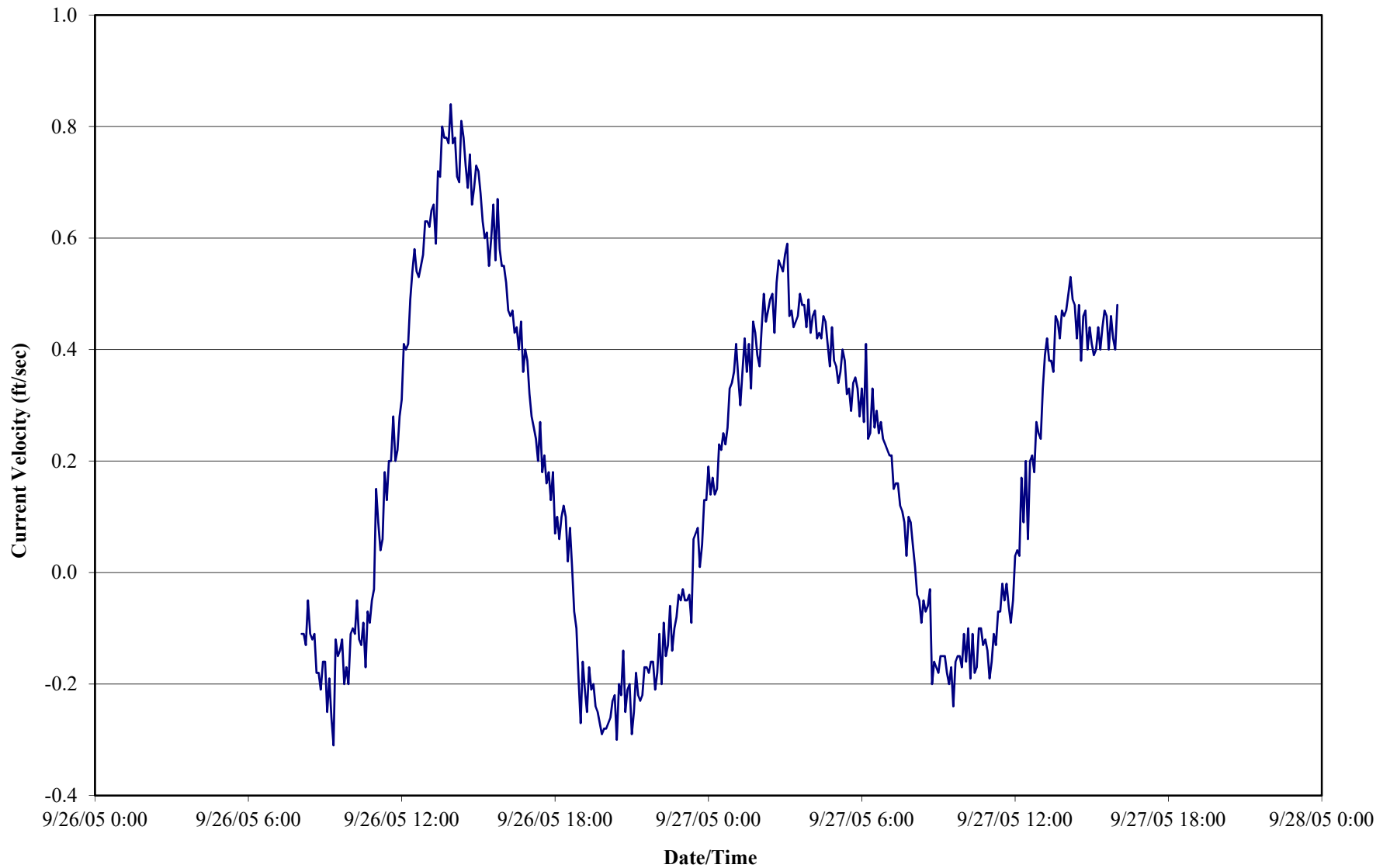


FIGURE 4-11.

PROFILE OF THE AVERAG CURRENT VELOCITY IN THE ST. JOHNS RIVER
NEAR OUTFALL D-001

Source: ECT, 2007.



Table 4-2. Tidal Currents in the St. Johns River near Outfall D-001

Percentile	Flood Tide Current Velocity (fps)	Ebb Tide Current Velocity (fps)
10 th	0.05	0.10
50 th	0.16	0.38
90 th	0.25	0.67

Source: ECT, 2007.

much greater than the 90th percentile daily average current (0.22 fps). Being conservative, the net river flow current velocities are used for mixing zone analysis, instead of the actual tidal current velocity.

Figure 4-12 presents the time series data of current direction in the St. Johns River near SGS Outfall D-001. Figure 4-13 shows the frequency analysis of the tidal current direction in the St. Johns River near SGS Outfall D-001. The analysis indicates the predominant ebb tide direction is 55° measured clockwise from the north, and the predominant flood tide direction is 234° measured clockwise from the north. The discharge structure is oriented in the downstream, ebbtide direction.

According to the stream flow data of the St. Johns River near Palatka, the average St. Johns River flow (5,040 cfs, or 3,257 MGD) is 569 times the AADF of the proposed Outfall D-001 discharge (5.72 MGD), including the new SCCF. Therefore, the ambient river will provide significant dilution to the SGS D-001 discharge.

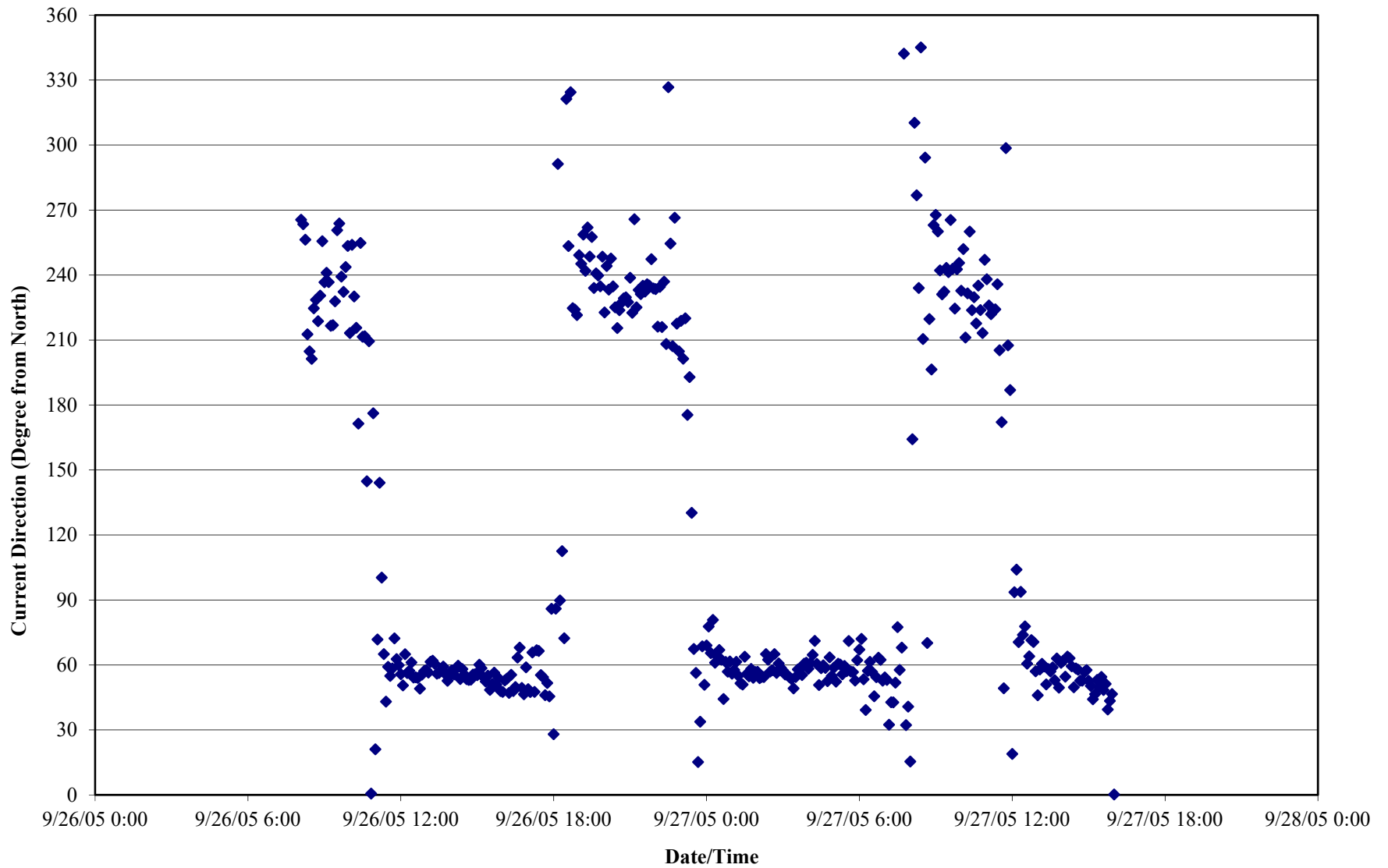


FIGURE 4-12.

CURRENT DIRECTION DATA IN THE ST. JOHNS RIVER NEAR OUTFALL D-001

Source: ECT, 2007.



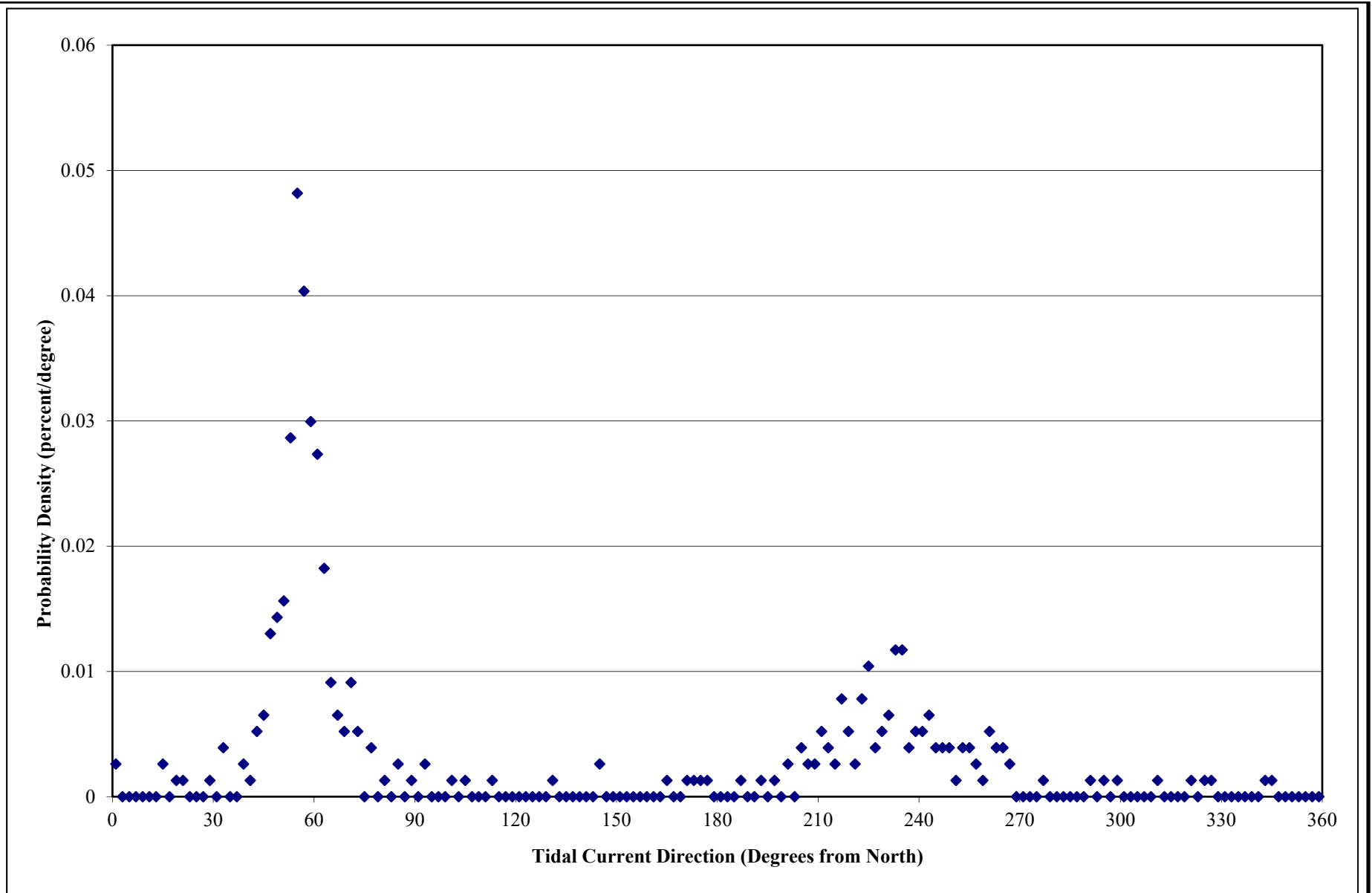


FIGURE 4-13.

FREQUENCY ANALYSIS OF TIDAL CURRENT DIRECTION IN ST. JOHNS RIVER NEAR OUTFALL D-001

Source: ECT, 2007.



5.0 MIXING ZONE ANALYSIS

According to Outfall D-001 water quality data presented in Section 3.0, mixing zones are needed for copper, cyanide, iron, mercury, selenium, specific conductance, water temperature, and temperature rise. Table 5-1 summarizes the effluent and ambient water quality and the proposed effluent limits. The following presents the mixing zone analysis for discharges through Outfall D-001 at SGS, including the flows for the SCCF Project.

5.1 METHODOLOGY

To quantify the mixing zone sizes for a mixing zone model, CORMIX was used for the calculations. CORMIX was developed by Cornell University under the sponsorship of EPA. It can simulate the initial jet turbulent mixing and transformation of the pollutant plume by buoyant spreading, turbulent dispersion, and advective mixing. CORMIX is capable of simulating a single-port submerged discharge, submerged multiport diffusers, or a surface discharge. The submerged multiport discharge option was used to simulate Outfall D-001 mixing zones in the St. Johns River.

5.2 MODEL SCENARIOS

According to the effluent and ambient water characterization presented in Sections 3.0 and 4.0, the water quality conditions presented in Table 5-2 were used for mixing zone analysis.

Table 5-2 also presents the dilution factor required at the edge of the mixing zone. The dilution factor required at the edge of the mixing zone is computed as follows:

$$\text{Dilution factor required} = \frac{(C - C_o)}{(C_{std} - C_o)}$$

where: C = effluent concentration.

C_o = ambient concentration.

C_{std} = water quality standard.

Table 5-1. Summary of Effluent and Ambient Water Quality and Mixing Zone Requirements

Parameter	Maximum D-001 Concentration Since 2001	Maximum D-001 Concentration Since 2011	95 th Percentile Ambient Concentration	Water Quality Standard*	Current Effluent Limit	Proposed Effluent Limit†
Copper (µg/L)	130	58.3	2.07	10.1	130	130
Cyanide (µg/L)	230	15	2.5	5.2	19.6	19.6
Iron (mg/L)	1.7	1.33	0.47	1	1.7	1.7
Mercury (µg/L)	0.146	0.146	0.00472	0.012	0.09	0.09
Selenium (µg/L)	16‡	6.6	2.5	5	11.7	11.7
Specific conductance (µmhos/cm)	8,538	7,700	1,420	2,130	8,653	8,653
Water Temperature (°F)	95.4	93.8	88.2	92	98.9	98.9
Delta-T (°F)	26.3	22.9	—	5	Not applicable	Not applicable

*The water quality standard for specific conductance is 1.5 times the ambient value.

Source: ECT, 2017.

Table 5-2. CORMIX Model Scenario and Dilution Requirement

Parameter	D-001	Ambient Water	Water Quality Standard	Dilution Required
AADF (MGD)	5.72	—	—	—
Copper (µg/L)	139	2.07	10.1	17.05
Conductivity (µmhos/cm)	8,653	1,420	2,130	10.19
Cyanide (µg/L)	19.6	2.7	5.2	6.76
Iron (mg/L)	1.7	0.47	1.0	2.32
Mercury (µg/L)	0.09	0.0047	0.012	11.68
Selenium (µg/L)	11.7	2.5	5	3.68
Temperature (permit) (°F)	98.9	88.2	92	2.82
Water density (summer) (kg/m ³)	996.89	995.92	—	—
Temperature (winter) (°F)	81.5	55.4	92	
Water density (winter) (kg/m ³)	997.81	999.89	—	—
Delta-T (°F)	26.3	—	5	5.26

Note: kg/m³ = kilogram per cubic meter.

Source: ECT, 2017.

As presented in Section 4.2, the tidal velocity is much higher than the daily average velocity, which represents net flow of the river. To ensure a conservative estimate (to overestimate) of the mixing zone, the high, median, and low daily average flows were used for both flood tide and ebb tide. Six ambient flow conditions were considered for each parameter:

- 90th percentile flood current (0.22 fps).
- Median flood current (0.084 fps).
- 10th percentile flood current (0.015 fps).
- 90th percentile ebb current (0.22 fps).
- Median ebb current (0.084 fps).
- 10th percentile ebb current (0.015 fps).

5.3 RESULTS

CORMIX computes the trajectory of the centerline of the effluent plume. The plume centerline concentration, dilution factor, and plume half-width (defined as the distance from the plume centerline to a location where the mixture is 37 percent of the centerline concentration) are computed and reported by the model.

The actual shape of a mixing zone typically resembles an elongated tear drop or a curved tear drop. The instantaneous mixing zone presented in this report is the rectangular enclosure, which can be much larger than the actual instantaneous mixing zone. The mixing zone envelope is also presented for each parameter. A mixing zone envelope represents a rectangular enclosure that includes all six instantaneous mixing zones under various ambient current scenarios. It is a conservative representation of the area that may encounter the instantaneous mixing zone at some time.

The CORMIX modeling results are presented in the following subsections.

Total Recoverable Copper

Table 5-3 presents the projected copper mixing zone size, with an effluent concentration of 139 µg/L. The results indicate the largest instantaneous mixing zone is 8.6 square meters

Table 5-3. Copper Mixing Zone Size

Current Condition	Mixing Zone Limits (meters)			Mixing Zone Size (m ²)
	Upstream	Downstream	Width	
High flood	3.1	0.0	2.5	7.8
Median flood	3.5	0.0	2.3	8.0
Low flood	3.9	0.0	2.2	8.6
High ebb	0.0	3.1	2.6	7.8
Median ebb	0.0	3.5	2.3	8.0
Low ebb	0.0	3.9	2.2	8.6
Composite envelope	3.9	3.9	2.6	20.3

Note: 95th percentile ambient concentration = 2.07 µg/L.

Class III freshwater quality standard = 10.1 µg/L.

Dilution factor needed = 17.05 at the edge of the mixing zone.

Effluent concentration = 139 µg/L.

Upstream = upstream of the St. Johns River.

Source: ECT, 2017.

(m²) (3.9 by 2.2 meters). The size of the composite mixing zone envelope is 20.3 m² (7.8 by 2.6 meters). The existing permitted copper mixing zone size is 723 m².

Total Cyanide

Table 5-4 shows the projected cyanide mixing zone size, with an effluent concentration of 19.6 µg/L. The results indicate the maximum instantaneous cyanide mixing zone is 1.9 m² (0.5 by 3.7 meters). The size of the composite mixing zone envelope is 3.9 m² (1.0 by 3.9 meters).

Total Recoverable Iron

Table 5-5 presents the projected iron mixing zone, with an effluent concentration of 1.7 mg/L. The results indicate the maximum instantaneous mixing zone size is 0.2 m² (0.05 by 4.2 meters). The size of the composite mixing zone envelope is 0.4 m² (0.1 by 4.2 meters). The existing permitted iron mixing zone size is 1.2 m².

Total Recoverable Mercury

Table 5-6 presents the projected mercury mixing zone size, with an effluent concentration of 0.09 µg/L. The results indicate the largest instantaneous mercury mixing zone is 4.9 m² (1.8 by 2.7 meters). The size of the composite mixing zone envelope is 10.9 m² (3.4 by 3.2 meters). The existing permitted mercury mixing zone size is 67,323 m².

Total Recoverable Selenium

Table 5-7 presents the projected selenium mixing zone, with an effluent concentration of 11.7 µg/L. The CORMIX modeling results indicate the largest instantaneous selenium mixing zone size is 0.4 m² (0.1 by 4.1 meters). The size of the composite mixing zone envelope is 0.8 m² (0.2 by 4.2 meters). The existing permitted selenium mixing zone size is 5.8 m².

Table 5-4. Cyanide Mixing Zone Size

Current Condition	Mixing Zone Limits (meters)			Mixing Zone Size (m ²)
	Upstream	Downstream	Width	
High flood	0.4	0.0	3.9	1.6
Median flood	0.5	0.0	3.7	1.9
Low flood	0.5	0.0	3.6	1.6
High ebb	0.0	0.4	3.9	1.6
Median ebb	0.0	0.5	3.7	1.9
Low ebb	0.0	0.5	3.6	1.6
Composite envelope	0.5	0.5	3.9	3.9

Note: 95th percentile ambient concentration = 2.7 µg/L.
Dilution factor needed = 6.76 at the edge of the mixing zone.
Effluent concentration = 19.6 µg/L.
Water quality standard = 5.2 µg/L.
Upstream = upstream of the St. Johns River.

Source: ECT, 2017.

Table 5-5. Iron Mixing Zone Size

Current Condition	Mixing Zone Limits (meters)			Mixing Zone Size (m ²)
	Upstream	Downstream	Width	
High flood	0.04	0.0	4.2	0.2
Median flood	0.05	0.0	4.2	0.2
Low flood	0.05	0.0	4.2	0.2
High ebb	0	0.04	4.2	0.2
Median ebb	0	0.05	4.2	0.2
Low ebb	0	0.05	4.2	0.2
Composite envelope	0.05	0.05	4.2	0.4

Note: 95th percentile ambient concentration = 0.47 mg/L.

Dilution factor needed = 2.32 at the edge of the mixing zone.

Effluent concentration = 1.7 mg/L.

Water quality standard = 1 mg/L.

Upstream = upstream of the St. Johns River.

Source: ECT, 2017.

Table 5-6. Mercury Mixing Zone Size

Current Condition	Mixing Zone Limits (meters)			Mixing Zone Size (m ²)
	Upstream	Downstream	Width	
High flood	1.3	0.0	3.2	4.2
Median flood	1.6	0.0	2.9	4.6
Low flood	1.8	0.0	2.7	4.9
High ebb	0.0	1.3	3.2	4.2
Median ebb	0.0	1.6	2.9	4.6
Low ebb	0.0	1.8	2.7	4.9
Composite envelope	1.7	1.7	3.2	10.9

Note: 95th percentile ambient concentration = 0.0047 µg/L.
Dilution factor needed = 11.68 at the edge of the mixing zone.
Effluent concentration = 0.09 µg/L.
Water quality standard = 0.012 µg/L.
Upstream = upstream of the St. Johns River.

Source: ECT, 2017.

Table 5-7. Selenium Mixing Zone Size

Current Condition	Mixing Zone Limits (meters)			Mixing Zone Size (m ²)
	Upstream	Downstream	Width	
High flood	0.1	0.0	4.2	0.4
Median flood	0.1	0.0	4.1	0.4
Low flood	0.1	0.0	4.1	0.4
High ebb	0	0.1	4.2	0.4
Median ebb	0	0.1	4.1	0.4
Low ebb	0	0.1	4.1	0.4
Composite envelope	0.1	0.1	4.2	0.8

Note: 95th percentile ambient concentration = 2.5 µg/L.
Dilution factor needed = 3.68 at the edge of the mixing zone.
Effluent concentration = 11.7 µg/L.
Water quality standard = 5 µg/L.
Upstream = upstream of the St. Johns River.

Source: ECT, 2017.

Specific Conductance

Table 5-8 shows the projected specific conductance mixing zone, with an effluent concentration of 8,653 $\mu\text{mhos/cm}$. The mixing zone modeling results indicate the greatest instantaneous mixing zone size is 3.9 m^2 (1.3 by 3 meters). The size of the composite mixing zone envelope is 8.8 m^2 (2.6 by 3.4 meters). The existing permitted mixing zone size for specific conductance is 176 m^2 .

Temperature

Two water quality criteria were considered for the thermal mixing zone:

- The water temperature at the edge of the mixing zone should not exceed 92°F per Rule 62-302.520(4)(a), Florida Administrative Code (F.A.C.).
- The delta-T (temperature difference between the instream and ambient temperatures) at the edge of the thermal mixing zone should not exceed 5°F per Rule 62-302.502(4)(a), F.A.C. The largest delta-T mixing zone would occur in winter, according to the data presented in Section 3.2.8.

Table 5-9 presents the projected thermal mixing zone, with a maximum discharge temperature limit of 98.9°F. The CORMIX modeling results indicate the largest instantaneous temperature mixing zone is 0.4 m^2 (0.1 by 4.2 meters). The size of the composite temperature mixing zone is 0.8 m^2 (0.2 by 4.2 meters).

Table 5-10 shows the projected delta-T mixing zone, with a maximum delta-T of 26.3°F. The CORMIX modeling results indicate the largest instantaneous delta-T mixing zone is 1.2 m^2 (0.3 by 4.0 meters). The size of the composite delta-T mixing zone envelope is 2.4 m^2 (0.6 by 4.0 meters). Therefore, delta-T is the controlling factor for the thermal mixing zone.

Table 5-11 summarizes the mixing zone analysis results. Appendix B contains a copy of the input and output of the CORMIX model.

Table 5-8. Specific Conductance Mixing Zone Size

Current Condition	Mixing Zone Limits (meters)			Mixing Zone Size (m ²)
	Upstream	Downstream	Width	
High flood	0.9	0.0	3.4	3.1
Median flood	1.1	0.0	3.1	3.4
Low flood	1.3	0.0	3.0	3.9
High ebb	0.0	0.9	3.4	3.1
Median ebb	0.0	1.1	3.1	3.4
Low ebb	0.0	1.3	3.0	3.9
Composite envelope	1.3	1.3	3.4	8.8

Note: 95th percentile ambient concentration = 1,420 µmhos/cm.
Dilution factor needed = 10.19 at the edge of the mixing zone.
Effluent concentration = 8,653 µmhos/cm.
Water quality standard = 2,130 µmhos/cm.
Upstream = upstream of the St. Johns River.

Source: ECT, 2017.

Table 5-9. Thermal Mixing Zone Size—Maximum Temperature

Current Condition	Mixing Zone Limits (meters)			Mixing Zone Size (m ²)
	Upstream	Downstream	Width	
High flood	0.1	0.0	4.2	0.4
Median flood	0.1	0.0	4.2	0.4
Low flood	0.1	0.0	4.2	0.4
High ebb	0.0	0.1	4.2	0.4
Median ebb	0.0	0.1	4.2	0.4
Low ebb	0.0	0.1	4.2	0.4
Composite envelope	0.1	0.1	4.2	0.8

Note: 95th percentile ambient temperature = 88.2°F.
Dilution factor needed = 2.82 at the edge of the mixing zone.
Effluent temperature = 98.9°F.
Water quality standard = 92°F.
Upstream = upstream of the St. Johns River.

Source: ECT, 2017.

Table 5-10. Thermal Mixing Zone Size—Delta-T

Current Condition	Mixing Zone Limits (meters)			Mixing Zone Size (m ²)
	Upstream	Downstream	Width	
High flood	0.2	0.0	4.0	0.8
Median flood	0.3	0.0	4.0	1.2
Low flood	0.3	0.0	3.8	1.1
High ebb	0	0.2	4.0	0.8
Median ebb	0	0.3	4.0	1.2
Low ebb	0	0.3	3.8	1.1
Composite envelope	0.3	0.3	4.0	2.4

Note: Ambient temperature = 51.7°F.
Delta-T = 26.3°F.
Dilution factor needed = 5.26 at the edge of the mixing zone.
Effluent temperature = 78.0°F.
Water quality standard = 5°F.
Upstream = upstream of the St. Johns River.

Source: ECT, 2017.

Table 5-11. Summary of Mixing Zone Analysis Results

Parameter	Proposed Effluent Limitation	Proposed Mixing Zone Limits (meters)			Mixing Zone Size (m ²)	
		Upstream	Downstream	Width	Proposed	Existing
Copper	139 µg/L	3.9	3.9	2.6	20.3	723
Cyanide	19.6 µg/L	0.5	0.5	3.9	3.9	125
Iron	1.7 mg/L	0.05	0.05	4.2	0.4	1.2
Mercury	0.09 µg/L	1.7	1.7	3.2	10.9	67,323
Selenium	11.7 µg/L	0.1	0.1	4.2	0.8	5.8
Specific conductivity	8,653 µmhos/cm	1.3	1.3	3.4	8.8	176
Temperature	98.9°F	0.1	0.1	4.2	0.8	6.9
Delta-T	26.3°F	0.3	0.3	4.0	2.4	18.5

Source: ECT, 2017.

6.0 SUMMARY

The results of this water quality assessment are summarized as follows:

- The average stream flow of the St. Johns River near Outfall D-001 is approximately 5,040 cfs (3,257 MGD), while the proposed D-001 AADF is 5.72 MGD. Therefore, the average dilution ratio between the ambient flow and effluent is 569 to 1.
- Mixing zones are needed for copper, cyanide, iron, mercury, selenium, specific conductance, temperature, and temperature rise. The dilution factor needed at the edge of the mixing zone ranges from 2.32 to 17.05.
- Table 6-1 summarizes the results of the mixing zone analysis and provides a comparison of the currently permitted mixing zones with the requested mixing zones submitted in the February 2017 NPDES permit renewal application and the proposed mixing zones with SCCF.

Table 6-1. Proposed Mixing Zone Size

Parameter	Effluent Limit		Mixing Zone Size (m ²)		
	Current	Proposed	Current Permit	Requested Permit Renewal	Proposed with SCCF Project
Copper (µg/L)	139	139	723	20.3	20.3
Cyanide (µg/L)	19.6	19.6	125	6.5*	3.9
Iron (mg/L)	1.7	1.7	1.2	0.4	0.4
Mercury (µg/L)	0.09	0.09	67,323	10.9	10.9
Selenium (µg/L)	11.7	11.7	5.8	0.8	0.8
Specific conductance (µmhos/cm)	8,653	8,653	176	8.8	8.8
Temperature (°F)	98.9	98.9	2.0	0.8	0.8
Delta-T	26.3	26.3	18.5	2.5	2.4

*Based on a total cyanide requested effluent limit of 24 µg/L. SECI anticipates retaining the 19.6-µg/L effluent limit resulting in a 3.9-square-meter mixing zone.

Source: ECT, 2017.

APPENDIX A

WATER QUALITY DATA AT OUTFALL D-001

Table A-1. Total Recoverable Iron Data at SGS Outfall D-001

Class III Water Quality Standard = 1.0 mg/L
D-001 Effluent Limitation = 1.7 mg/L

Date	Iron (mg/L)
02/01/01	0.46
06/19/01	0.43
07/17/01	0.48
11/19/01	1.1
02/20/02	0.7
06/12/02	0.3
07/30/02	0.32
10/22/02	0.800
01/28/03	0.67
05/13/03	0.61
08/26/03	0.54
10/28/03	0.65
02/04/04	1.10
04/29/04	1.0
07/29/04	0.54
10/12/04	1.6
01/25/05	1.4
05/17/05	0.69
08/10/05	0.77
10/18/05	1.7
01/24/06	1.2
04/04/06	1.0
08/15/06	0.64
12/05/06	0.91
02/05/07	0.39
04/02/07	0.21
07/09/07	0.578
10/09/07	0.59
01/07/08	0.48
04/01/08	0.40
07/07/08	0.24
10/13/08	1.1
01/05/09	1.1
04/13/09	0.66
07/06/09	0.456
10/01/09	1.13
01/04/10	0.875
04/12/10	0.750
07/06/10	0.60
10/11/10	0.48
01/03/11	0.31
04/11/11	0.31

Table A-1. Total Recoverable Iron Data at SGS Outfall D-001

Class III Water Quality Standard = 1.0 mg/L
D-001 Effluent Limitation = 1.7 mg/L

Date	Iron (mg/L)
07/05/11	0.42
10/10/11	0.48
01/17/12	0.53
05/19/12	0.36
07/17/12	0.88
10/09/12	0.84
01/15/13	0.73
05/20/13	0.36
08/13/13	0.52
12/03/13	0.21
02/11/14	1.05
05/06/14	0.30
07/15/14	0.34
11/04/14	0.51
01/13/15	0.53
05/05/15	1.03
07/14/15	0.81
10/20/15	1.33
01/26/16	0.60
04/18/16	0.59
07/12/16	0.33
Average	0.68
Maximum	1.70
Standard Dev	0.34
95 th Percentile	1.32

Source: SECI, 2011.
ECT, 2011.

Table A-2. Total Recoverable Copper Data at SGS Outfall D-001

Class III Water Quality Standard = 10.12 µg/L
D-001 Effluent Limitation = 139.0 µg/L

Date	Lab Reported Value (µg/L)	Value Used (µg/L)	Remark Code	MDL (µg/L)	PQL (µg/L)
02/01/01	44.0	44.0			
06/19/01	27.0	27.0			
07/17/01	24.0	24.0			
11/19/01	70.0	70.0			
02/20/02	41.0	41.0			
06/12/02	37.0	37.0			
07/30/02	40.0	40.0			
10/22/02	40.0	40.0			
01/28/03	32.0	32.0			
05/13/03	25.0	25.0			
08/26/03	22.0	8.0	I	8	
10/28/03	30.0	30.0			
02/04/04	29.0	1.8	I	1.8	40
04/29/04	57	57.0			
07/27/04	130	130.0			
10/12/04	58	58.0			
01/25/05	34	34.0			
05/17/05	45	45.0			
08/10/05	31	31.0			
10/18/05	20	20.0			
01/24/06	23	23.0			
04/04/06	32	32.0			
08/15/06	23	23.0			
12/05/06	39	39.0			
02/05/07	31	31.0			
04/02/07	19	19.0			
07/09/07	23	23.0			
10/09/07	34	34.0			
01/07/08	80	80.0			
04/01/08	51	51.0			
07/07/08	36	36.0			
10/13/08	41	41.0			
01/05/09	38	38.0			
04/13/09	25	25.0			
07/06/09	20.0	20.0			
10/01/09	11.2	11.2			
01/04/10	45.2	45.2			
04/12/10	15.0	15.0			
07/06/10	23.0	23.0			
10/11/10	32.4	32.4			
01/03/11	36.8	36.8			

Table A-2. Total Recoverable Copper Data at SGS Outfall D-001

Class III Water Quality Standard = 10.12 µg/L
D-001 Effluent Limitation = 139.0 µg/L

Date	Lab Reported Value (µg/L)	Value Used (µg/L)	Remark Code	MDL (µg/L)	PQL (µg/L)
04/11/11		33.5			
07/05/11		31.4			
10/10/11		14.4			
01/17/12		37.9			
05/16/12		45.3			
07/17/12		26.7			
10/09/12		31.3			
01/15/13		29.5			
05/20/13		11.6			
08/13/13		31.2			
12/03/13		45.7			
02/11/14		22.9			
05/06/14		50.5			
07/15/14		26.2			
11/04/14		23.3			
01/13/15		32.3			
05/05/15		58.3			
07/14/15		54.8			
10/20/15		30.6			
01/26/16		35.0			
04/18/16		37.9			
07/12/16		40.1			
Average		35.30			
Maximum		130.00			
Standard Dev		18.61			
95 th Percentile		58.27			

Sources: SECI, 2011.
ECT, 2011.

Table A-3. Total Cyanide Data at SGS Outfall D-001

Class III Water Quality Standard = 5.2 µg/L
D-001 Effluent Limitation = 19.6 µg/L

Date		Lab Reported Value (µg/L)	Value Used (µg/L)	Remark Code	MDL (µg/L)	PQL (µg/L)	Analytical Method
02/01/01		19.0	19.0				
06/19/01		17.0	17.0		10		E335.2
07/17/01		15.0	15.0		10		E335.2
11/19/01		25.0	25.0		10		E335.2
02/20/02		25.0	25.0		5		E335.2
06/12/02		14.0	14.0		5	16	E335.2
07/30/02		4.0	4.0				E335.2
10/22/02		16.0	16.0		4	16	E335.2 LV
01/28/03		8.0	4.0	I	4	16	E335.2 LV
05/13/03		8.0	4.0	I	4	16	E335.2 LV
08/26/03	<	18.0	9.0	U	18	72	E335.2 LV
10/28/03	<	18.0	9.0	U	18	72	E335.2 LV
02/04/04		32.0	32.0	I	18	72	E335.2 LV
04/27/04	<	18.0	9.0	U	18	72	E335.2 LV
07/27/04	<	18.0	9.0	U	18	72	E335.2 LV
10/12/04	<	18.0	9.0	U	18	72	E335.2 LV
01/25/05	<	18.0	9.0	U	18	72	E335.2 LV
05/17/05	<	18.0	9.0	U	18	72	E335.2 LV
08/10/05		40.0	18.0	I	18	72	E335.2 LV
10/18/05		31.8	31.8		3.8	10	E335.3
01/24/06	<	18.0	9.0	U	18	72	E335.2 LV
04/04/06	<	38.0	36.0	I	36	144	E335.2 LV
08/15/06		60.0	13.0	I	13	52	E335.2 LV
12/05/06		36.0	36.0		2.2	10	E335.3
02/05/07		92.0	92.0		2.2	10	E335.3
03/05/07		22.0	22.0		2.2	10	E335.3
04/02/07		120.0	120.0		2.2	10	E335.3
05/07/07		26.0	26.0		2.2	10	E335.3
06/12/07		5.76	2.9	I	2.9	10	E335.3
07/02/07		8.0	1.5	I	1.5	10	E335.3
08/06/07		22.0	22.0		1.5	10	E335.3
09/03/07		24.0	24.0		1.5	10	E335.3
10/01/07		37.0	37.0		1.5	10	E335.3
11/05/07		46.0	46.0		1.5	10	E335.3
12/03/07		8.0	1.5	I	1.5	10	E335.3
01/02/08		17.0	17.0		1.5	10	EPA 335.4
02/05/08		85.0	85.0		1.5	10	EPA 335.4
03/03/08		100.0	100.0		1.5	10	EPA 335.4
04/01/08		64.0	64.0		1.5	10	EPA 335.4
05/05/08		30.0	30.0		1.5	10	EPA 335.4
06/02/08		42.0	42.0		2.8	10	EPA 335.4

Table A-3. Total Cyanide Data at SGS Outfall D-001

Class III Water Quality Standard = 5.2 µg/L
D-001 Effluent Limitation = 19.6 µg/L

Date	Lab Reported Value (µg/L)	Value Used (µg/L)	Remark Code	MDL (µg/L)	PQL (µg/L)	Analytical Method
07/01/08	140.0	140.0		2.8	10	EPA 335.4
08/04/08	230.0	230.0		5	14	EPA 335.4
09/02/08	55.0	55.0		14	50	EPA 335.4
10/13/08	20.0	14.0	I	14	50	EPA 335.4
11/03/08	16.0	16.0		14	50	EPA 335.4
12/02/08	27.0	27.0		4	10	EPA 335.4
01/05/09	< 14.0	7.0	U	14	50	EPA 335.4
02/02/09	< 5.0	2.5	U	5	5	SM-4500 CN E
03/02/09	9.9	9.9		5	5	SM-4500 CN E
04/13/09	7.9	7.9		14	50	EPA 335.4
05/04/09	7.9	7.9		14	50	EPA 335.4
06/02/09	< 4.0	2.0	U	4	10	EPA 335.4
07/06/09	< 4.0	2.0	U	4	10	EPA 335.4
08/10/09	5.1	5.0	I	5	10	EPA 335.4
09/01/09	9.0	5.0	I	5	10	EPA 335.4
10/01/09	< 5.0	2.5	U	5		EPA 335.4
11/02/09	< 5.0	2.5	U	5		EPA 335.4
12/02/09	7.8	5.0	I	5	10	EPA 335.4
01/04/10	18.0	18.0				EPA 335.4
02/01/10	< 5.0	2.5	U	5		EPA 335.4
04/12/10	5.0	5.0	I	5	10	EPA 335.4
05/04/10	8.6	5.0	I	5	10	EPA 335.4
06/01/10	5.1	5.0	I	5	10	EPA 335.4
07/06/10	9.1	5.0	I	5	10	EPA 335.4
08/02/10	11.0	11.0				EPA 335.4
09/07/10	11.0	11.0				EPA 335.4
10/11/10	7.5	5.0	I	5	10	EPA 335.4
11/01/10	9.9	5.0	I	5	10	EPA 335.4
12/06/10	15.0	15.0				EPA 335.4
01/03/11	< 5.0	2.5	U	5		EPA 335.4
02/15/11	6.9	5.0	I	5	10	EPA 335.4
03/01/11	9.6	5.0	I	5	10	EPA 335.4
04/11/11	10.0	10.0				
05/09/11	7.4	7.4				
06/06/11	5	5.0				
07/05/11	9.8	9.8				
08/01/11	10	10.0				
09/12/11	8.3	8.3				
10/10/11	8.8	8.8				
11/21/11	11	11.0				
12/05/11	9.2	9.2				

Table A-3. Total Cyanide Data at SGS Outfall D-001

Class III Water Quality Standard = 5.2 µg/L
D-001 Effluent Limitation = 19.6 µg/L

Date	Lab Reported Value (µg/L)	Value Used (µg/L)	Remark Code	MDL (µg/L)	PQL (µg/L)	Analytical Method
01/17/12	12	12.0				
02/14/12	7.8	7.8				
03/13/12	8	8.0				
04/10/12	12	12.0				
05/16/12	9.4	9.4				
06/19/12	9.6	9.6				
07/17/12	6.9	6.9				
08/14/12	5	5.0				
09/11/12	7.4	7.4				
10/09/12	13	13.0				
11/06/12	10	10.0				
12/03/12	6.3	6.3				
01/15/13	3	3.0				
02/12/13	15	15.0				
03/12/13	14	14.0				
04/09/13	3	3.0				
05/20/13	3	3.0				
06/04/13	3	3.0				
07/16/13	3	3.0				
08/13/13	3	3.0				
09/10/13	5	5.0				
10/18/13	8	8.0				
11/04/13	3	3.0				
12/03/13	3	3.0				
01/14/14	3	3.0				
02/11/14	3	3.0				
03/11/14	3	3.0				
04/01/14	7	7.0				
05/06/14	7	7.0				
06/04/14	8	8.0				
07/01/14	8	8.0				
08/12/14	9	9.0				
09/09/14	4	4.0				
10/07/14	3	3.0				
11/04/14	10	10.0				
12/02/14	8	8.0				
01/13/15	7	7.0				
02/10/15	4	4.0				
03/10/15	6	6.0				
04/07/15	5	5.0				
05/05/15	7	7.0				

Table A-3. Total Cyanide Data at SGS Outfall D-001

Class III Water Quality Standard = 5.2 µg/L
D-001 Effluent Limitation = 19.6 µg/L

Date	Lab Reported Value (µg/L)	Value Used (µg/L)	Remark Code	MDL (µg/L)	PQL (µg/L)	Analytical Method
06/01/15	6	6.0				
07/14/15	4	4.0				
08/11/15	5	5.0				
09/08/15	4	4.0				
10/06/15	8	8.0				
11/03/15	7	7.0				
12/02/15	7	7.0				
01/18/16	1.3	1.3				
02/09/16	8	8.0				
03/08/16	5	5.0				
04/18/16	11	11.0				
05/03/16	4	4.0				
06/14/16	4	4.0				
07/12/16	9	9.0				
08/09/16	14	14.0				
09/06/16	11	11.0				
Average		15.96				
Maximum		230.00				
Standard Dev		27.95				
95 th Percentile		55.90				

Source: SECI, 2011.
ECT, 2011.

Table A-4. Selenium Data at SGS Outfall D-001

Class III Water Quality Standard = 5 µg/L
D-001 Effluent Limitation = 11.7 µg/L

Date		Lab Reported Value (µg/L)	Value Used (µg/L)	Remark Code	MDL (µg/L)	PQL (µg/L)
02/01/01	<	3.3	1.65	U	3.3	
06/19/01	<	3.3	1.65	U	3.3	
07/17/01		5.1	5.10			
11/19/01	<	5	2.50	U	5	
02/20/02	<	3.3	1.65	U	3.3	
06/12/02	<	2.0	1.00	U	2	
07/30/02		5.1	5.10			
10/22/02		11.0	11.00			
01/28/03		7.9	4.20	I	4.2	
05/13/03		6.9	4.20	I	4.2	
08/26/03	<	8.4	4.20	U	8.4	20
10/28/03		8.0	4.20	I	4.2	10
02/04/04		13.0	13.00		8.4	20
04/29/04		7.2	6.50	I	6.5	100
07/29/04		4.9	1.30	I	1.3	25
10/12/04		7.0	1.30	I	1.3	25
01/25/05		7.2	1.30	I	1.3	25
05/17/05		2.4	2.40			
08/10/05		7.5	7.50			
10/18/05		7.1	7.10			
01/24/06	<	7.9	3.95	U	7.9	
04/04/06		14	14.00			
08/15/06		12	12.00			
12/05/06		12	12.00			
02/05/07		5.7	4.00	I	4	10
03/05/07	<	4	2.00	U	4	
04/02/07		16	16.00		4	10
05/14/07	<	4	2.00	U		
06/11/07		6.9	4.00	I	4	10
07/02/07		12	12.00			
08/06/07		4.9	4.00	I	4	10
09/03/07		13	13.00			
10/09/07	<	4	2.00	U	4	
11/12/07	<	3.9	1.95	U	3.9	
12/10/07	<	3.9	1.95	U	3.9	
01/07/08		5.6	3.90	I	3.9	10
02/04/08		7.2	3.90	I	3.9	10
03/03/08		9.7	3.90	I	3.9	10
04/01/08	<	3.5	1.75	U	3.5	
05/12/08		9	3.50	I	3.5	10
06/09/08		6.1	3.50	I	3.5	10

Table A-4. Selenium Data at SGS Outfall D-001

Class III Water Quality Standard = 5 µg/L
D-001 Effluent Limitation = 11.7 µg/L

Date		Lab Reported Value (µg/L)	Value Used (µg/L)	Remark Code	MDL (µg/L)	PQL (µg/L)
07/07/08	<	3.5	1.75	U	3.5	
08/04/08		7.8	3.50	I	3.5	10
09/02/08		4.8	4.80	I	3.5	10
10/13/08	<	3.5	1.75	U	3.5	
11/10/08		7.6	3.50	I	3.5	10
12/08/08	<	3.5	1.75	U	3.5	
01/05/09	<	3.5	1.75	U	3.5	
02/02/09	<	3.5	1.75	U	3.5	
03/02/09		5.2	3.50	I	3.5	10
04/13/09	<	4	2.00	U	4	
05/04/09	<	4	2.00	U	4	
06/08/09	<	4	2.00	U	4	
07/06/09	<	3.5	1.75	U	3.5	
08/04/09		7	7.00			
09/01/09		7	7.00			
10/01/09	<	4	2.00	U	4	
11/09/09		1.6	1.60			
12/02/09		1.2	1.20			
01/04/10		2.7	2.70			
02/01/10		1.9	1.90			
04/12/10		1.2	1.20			
05/10/10		1.9	1.90			
06/07/10		1.8	1.80			
07/06/10		1.8	1.80			
08/02/10		2.6	2.60			
09/14/10		2.7	2.70			
10/11/10		7.0	7.00			
11/08/10		2.6	2.60			
12/06/10		6.1	6.10			
01/03/11		2.7	2.70			
02/15/11		2.9	2.90			
03/01/11		2.4	2.40			
04/11/11		1.5	1.50			
05/09/11		3.3	3.30			
06/06/11		3.2	3.20			
07/05/11		4.1	4.10			
08/01/11		1.8	1.80			
09/12/11		2.5	2.50			
10/10/11		2.2	2.20			
11/21/11		1.7	1.70			
12/05/11		3.3	3.30			

Table A-4. Selenium Data at SGS Outfall D-001

Class III Water Quality Standard = 5 µg/L
 D-001 Effluent Limitation = 11.7 µg/L

Date	Lab Reported Value (µg/L)	Value Used (µg/L)	Remark Code	MDL (µg/L)	PQL (µg/L)
01/17/12	3.1	3.10			
02/14/12	1.2	1.20			
03/13/12	2.7	2.70			
04/10/12	1.3	1.30			
05/16/12	4.0	4.00			
06/19/12	2.9	2.90			
07/17/12	2.2	2.20			
08/14/12	3.1	3.10			
09/11/12	2.4	2.40			
10/09/12	1.6	1.60			
11/06/12	1.6	1.60			
12/03/12	2.2	2.20			
01/15/13	1.1	1.10			
02/12/13	2.3	2.30			
03/12/13	2.2	2.20			
04/09/13	2.2	2.20			
05/20/13	2.9	2.90			
06/04/13	4.7	4.70			
07/16/13	2.2	2.20			
08/13/13	2.2	2.20			
09/10/13	1.1	1.10			
10/18/13	4.0	4.00			
11/04/13	2.3	2.30			
12/03/13	2.3	2.30			
01/14/14	4.9	4.90			
02/11/14	2.4	2.40			
03/11/14	1.8	1.80			
04/08/14	1.1	1.10			
05/06/14	2.7	2.70			
06/04/14	2.4	2.40			
07/01/14	1.8	1.80			
08/12/14	2.8	2.80			
09/09/14	2.8	2.80			
10/07/14	2.7	2.70			
11/04/14	1.8	1.80			
12/02/14	3.1	3.10			
01/13/15	6.6	6.60			
02/10/15	2.9	2.90			
03/11/15	2.5	2.50			
04/07/15	1.3	1.30			
05/05/15	3.1	3.10			

Table A-4. Selenium Data at SGS Outfall D-001

Class III Water Quality Standard = 5 µg/L
D-001 Effluent Limitation = 11.7 µg/L

Date	Lab Reported Value (µg/L)	Value Used (µg/L)	Remark Code	MDL (µg/L)	PQL (µg/L)
06/01/15	2.0	2.00			
07/14/15	2.6	2.60			
08/11/15	3.3	3.30			
09/08/15	6.4	6.40			
10/06/15	3.8	3.80			
11/03/15	3.7	3.70			
12/02/15	3.0	3.00			
01/26/16	3.9	3.90			
02/09/16	3.5	3.50			
03/08/16	2.3	2.30			
04/18/16	1.4	1.40			
05/03/16	1.1	1.10			
06/14/16	3.0	3.00			
07/12/16	4.1	4.10			
08/09/16	6.0	6.00			
09/06/16	6.0	6.00			
Average	3.51				
Maximum	16.00				
Standard Dev	2.76				
95 th Percentile	11.10				

Source: SECI, 2011.
ECT, 2011.

Table A-5. Mercury Data at SGS Outfall D-001

Class III Water Quality Standard = 0.012 µg/L
 Current Mercury Effluent Limitation = 0.09 µg/L

Date	Lab Reported Value (µg/L)	Value Used (µg/L)	Analytical Method	MDL (µg/L)	PQL (µg/L)	Remark Code
12/04/00	0.02805	0.02805	1631E			
01/24/01	0.05475	0.05475	1631E			
03/21/01	0.074	0.074	1631E			
04/09/01	0.0596	0.0596	1631E			
05/07/01	0.06265	0.06265	1631E			
06/06/01	0.0714	0.0714	1631E			
07/02/01	0.0518	0.0518	1631E			
08/08/01	0.0258	0.0258	1631E			
09/05/01	0.0381	0.0381	1631E			
10/04/01	0.01955	0.01955	1631E			
11/17/01	0.00705	0.00705	1631E			
12/04/01	0.0062	0.0062	1631E			
01/14/02	0.00945	0.00945	1631E			
02/11/02	0.01045	0.01045	1631E			
03/11/02	0.0056	0.0056	1631E			
04/08/02	0.00145	0.00145	1631E			
05/13/02	0.00675	0.00675	1631E			
06/05/02	0.00685	0.00685	1631E			
07/09/02	0.0225	0.0225	1631E			
10/16/02	0.0189	0.0189	1631E			
01/28/03	0.01805	0.01805	1631E			
05/13/03	0.01095	0.01095	1631E			
08/26/03	0.0185	0.0185	1631E			
10/30/03	0.0089	0.0089	1631E			
02/04/04	0.0013	0.0013	1631E			
04/27/04	0.0127	0.0127	1631E			
07/29/04	0.0066	0.0066	1631E			
10/12/04	0.0099	0.0099	1631E			
02/23/05	0.0094	0.0094	1631E			
03/24/05	0.012	0.012	1631E			
04/26/05	0.013	0.013	1631E			
05/17/05	0.0069	0.0069	1631E			
06/20/05	0.019	0.019	1631E			
07/25/05	0.013	0.013	1631E			
08/31/05	0.0067	0.0067	1631E			
09/27/05	0.0066	0.0066	1631E			
10/31/05	0.0087	0.0087	1631E			
11/29/05	0.019	0.019	1631E			
12/20/05	0.015	0.015	1631E			
01/30/06	0.008	0.008	1631E			
04/11/06	0.016	0.016	1631E			
07/11/06	0.01	0.01	1631E			
02/05/07	0.0057	0.0057	1631E			
02/19/07	0.012	0.012	1631E			

Table A-5. Mercury Data at SGS Outfall D-001

Class III Water Quality Standard = 0.012 µg/L
 Current Mercury Effluent Limitation = 0.09 µg/L

Date	Lab Reported Value (µg/L)	Value Used (µg/L)	Analytical Method	MDL (µg/L)	PQL (µg/L)	Remark Code
03/05/07	0.006	0.006	1631E			
04/02/07	0.0036	0.00025	1631E	0.00025	0.005	I
05/07/07	0.0041	0.0041	1631E			
06/05/07	0.0033	0.00025	1631E	0.00025	0.005	I
07/02/07	0.0199	0.0199	1631E			
08/06/07	0.0212	0.0212	1631E			
09/03/07	0.0204	0.0204	1631E			
10/09/07	0.0153	0.0153	1631E			
11/05/07	0.0159	0.0159	1631E			
12/03/07	0.0073	0.0073	1631E			
01/02/08	0.0133	0.0133	1631E			
02/05/08	0.0053	0.0053	1631E			
03/03/08	0.0022	0.0022	1631E			
04/01/08	0.0042	0.0042	1631E			
05/05/08	0.0132	0.0132	1631E			
06/02/08	0.00151	0.00151	1631E			
07/01/08	0.00473	0.00473	1631E			
08/04/08	0.00862	0.00862	1631E			
09/02/08	0.0106	0.0106	1631E			
10/06/08	0.0183	0.0183	1631E			
11/03/08	0.00794	0.00794	1631E			
12/02/08	0.0481	0.0481	1631E			
01/05/09	0.0229	0.0229	1631E			
02/02/09	0.0178	0.0178	1631E			
03/02/09	0.094	0.094	1631E			
04/13/09	0.0143	0.0143	1631E			
05/04/09	0.00618	0.00618	1631E			
06/01/09	0.046	0.046	1631E			
07/06/09	0.0867	0.0867	1631E			
08/04/09	0.0618	0.0618	1631E			
09/01/09	0.0851	0.0851	1631E			
10/01/09	0.0123	0.0123	1631E			
11/02/09	0.0219	0.0219	1631E			
12/02/09	0.0887	0.0887	1631E			
01/04/10	0.0804	0.0804	1631E			
02/01/10	0.0524	0.0524	1631E			
04/12/10	0.146	0.146	1631E			
05/04/10	0.036	0.036	1631E			
06/01/10	0.0462	0.0462	1631E			
07/06/10	0.0296	0.0296	1631E			
08/02/10	0.0215	0.0215	1631E			
09/07/10	0.0235	0.0235	1631E			
10/11/10	0.0224	0.0224	1631E			
11/01/10	0.0294	0.0294	1631E			

Table A-5. Mercury Data at SGS Outfall D-001

Class III Water Quality Standard = 0.012 µg/L
 Current Mercury Effluent Limitation = 0.09 µg/L

Date	Lab Reported Value (µg/L)	Value Used (µg/L)	Analytical Method	MDL (µg/L)	PQL (µg/L)	Remark Code
12/06/10	0.0734	0.0734	1631E			
01/03/11	0.0894	0.0894	1631E			
02/15/11	0.0531	0.0531	1631E			
03/15/11	0.0454	0.0454	1631E			
04/15/11	0.0431	0.0431				
05/25/11	0.0409	0.0409				
06/20/11	0.0559	0.0559				
07/05/11	0.0395	0.0395				
08/01/11	0.0541	0.0541				
09/12/11	0.11	0.11				
10/06/11	0.041	0.041				
11/21/11	0.0535	0.0535				
12/05/11	0.131	0.131				
01/17/12	0.0883	0.0883				
02/14/12	0.0598	0.0598				
03/13/12	0.136	0.136				
04/18/12	0.0537	0.0537				
05/16/12	0.131	0.131				
06/19/12	0.0987	0.0987				
07/17/12	0.0804	0.0804				
08/14/12	0.0426	0.0426				
09/11/12	0.071	0.071				
10/09/12	0.0333	0.0333				
11/06/12	0.00965	0.00965				
12/03/12	0.0975	0.0975				
01/15/13	0.0645	0.0645				
02/12/13	0.102	0.102				
03/12/13	0.0497	0.0497				
04/09/13	0.0598	0.0598				
05/20/13	0.013	0.013				
06/04/13	0.0536	0.0536				
07/16/13	0.0485	0.0485				
08/13/13	0.0484	0.0484				
09/10/13	0.0293	0.0293				
10/18/13	0.11	0.11				
11/04/13	0.042	0.042				
12/03/13	0.039	0.039				
01/14/14	0.029	0.029				
02/11/14	0.014	0.014				
03/11/14	0.023	0.023				
04/08/14	0.0094	0.0094				
05/06/14	0.018	0.018				
06/04/14	0.011	0.011				
07/01/14	0.014	0.014				

Table A-5. Mercury Data at SGS Outfall D-001

Class III Water Quality Standard = 0.012 µg/L
 Current Mercury Effluent Limitation = 0.09 µg/L

Date	Lab Reported Value (µg/L)	Value Used (µg/L)	Analytical Method	MDL (µg/L)	PQL (µg/L)	Remark Code
08/12/14	0.02	0.02				
09/09/14	0.028	0.028				
10/07/14	0.0073	0.0073				
11/04/14	0.014	0.014				
12/02/14	0.0094	0.0094				
01/13/15	0.048	0.048				
02/10/15	0.087	0.087				
03/10/15	0.018	0.018				
04/07/15	0.01	0.01				
05/05/15	0.039	0.039				
06/01/15	0.062	0.062				
07/14/15	0.042	0.042				
08/11/15	0.052	0.052				
09/08/15	0.35	0.35				
10/06/15	0.063	0.063				
11/03/15	0.017	0.017				
12/02/15	0.037	0.037				
01/18/16	0.0023	0.0023				
02/09/16	0.033	0.033				
03/08/16	0.032	0.032				
04/18/16	0.0028	0.0028				
05/03/16	0.0215	0.0215				
06/14/16	0.0028	0.0028				
07/12/16	0.018	0.018				
08/09/16	0.009	0.009				
09/06/16	0.014	0.014				
Average		0.0361				
Maximum		0.3500				
Standard Dev		0.0403				
95 th Percentile		0.0992				

Note: Only low level mercury analyses (Method 1631E) were included.

Sources: SECI 2011
 ECT, Inc. 2011

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
D-001 Effluent Limitation : 8,653 $\mu\text{mhos/cm}$
95th percentile of ambient : 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
12/13/00	7200	05/16/12	6040
02/01/01	7700	07/17/12	6520
06/19/01	7000	10/09/12	6420
07/17/01	8360	01/15/13	5610
11/19/01	5140	05/20/13	6910
02/20/01	6190	08/13/13	6790
06/12/02	6420	12/03/13	4560
07/30/02	7430	02/11/14	6000
10/22/02	6530	05/06/14	5600
01/28/03	6090	07/15/14	6100
05/13/03	6490	11/04/14	3680
08/26/03	6530	01/13/15	4540
10/28/03	6420	05/05/15	5510
02/04/04	7680	07/14/15	6930
04/29/04	6820	10/20/15	6084
07/27/04	7860	01/26/16	7595
10/12/04	5990	04/18/16	6910
01/25/05	6680	07/12/16	7700
05/17/05	6360		
08/10/05	6380	01/02/04	5710
10/18/05	7990	01/05/04	5570
01/24/06	6840	01/06/04	6010
04/04/06	7810	01/07/04	5850
08/15/06	7840	01/08/04	6270
12/05/06	7720	01/09/04	6380
02/05/07	7170	01/12/04	6170
04/02/07	8080	01/13/04	6660
07/09/07	7910	01/14/04	3960
10/09/07	8120	01/15/04	7600
01/07/08	7520	01/16/04	7020
04/01/08	7250	01/19/04	7910
07/07/08	8100	01/20/04	5880
10/13/08	7120	01/22/04	7010
01/05/09	6140	01/23/04	7210
04/13/09	6590	01/26/04	3980
07/06/09	6900	01/27/04	7030
10/01/09	4420	01/28/04	7600
01/04/10	8030	01/29/04	6840
04/12/10	4700	01/30/04	6870
07/06/10	6480	02/02/04	7790
10/11/10	5800	02/03/04	4680
01/03/11	5700	02/04/04	7720
04/11/11	5960	02/05/04	8270
07/05/11	6820	02/06/04	7190
10/10/11	5280	02/09/04	7570
01/17/12	5460	02/10/04	8130

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
02/11/04	7110	04/19/04	6880
02/12/04	7360	04/20/04	7010
02/16/04	4430	04/21/04	6910
02/17/04	3190	04/22/04	7190
02/18/04	3050	04/23/04	7610
02/19/04	2920	04/26/04	6010
02/20/04	2920	04/27/04	6560
02/23/04	6630	04/28/04	7580
02/24/04	6480	04/29/04	7190
02/25/04	6570	04/30/04	7680
02/26/04	6210	05/03/04	7480
02/27/04	6130	05/04/04	5010
03/01/04	3450	05/05/04	7890
03/02/04	6930	05/06/04	4870
03/03/04	6460	05/07/04	7020
03/04/04	5420	05/10/04	6630
03/08/04	5330	05/11/04	7360
03/09/04	6450	05/12/04	7630
03/10/04	7340	05/13/04	7310
03/11/04	7010	05/14/04	5840
03/12/04	4820	05/17/04	7610
03/15/04	6690	05/18/04	5930
03/16/04	6270	05/19/04	7350
03/17/04	6530	05/20/04	6860
03/18/04	3100	05/21/04	7400
03/19/04	6410	05/24/04	7530
03/22/04	7260	05/25/04	6850
03/23/04	4960	05/26/04	6560
03/24/04	3690	05/27/04	4230
03/25/04	7950	05/28/04	7590
03/26/04	7090	06/01/04	7140
03/29/04	5190	06/02/04	5560
03/30/04	6960	06/03/04	7000
03/31/04	7100	06/04/04	7870
04/01/04	5500	06/07/04	7740
04/02/04	5500	06/08/04	8030
04/05/04	6200	06/09/04	7530
04/06/04	6400	06/10/04	7410
04/07/04	6320	06/11/04	7600
04/08/04	5280	06/14/04	8110
04/09/04	6740	06/15/04	7660
04/12/04	5380	06/16/04	7740
04/13/04	4520	06/18/04	6680
04/14/04	6010	06/21/04	7790
04/15/04	7030	06/22/04	7570
04/16/04	6330	07/01/04	8320

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
07/02/04	7500	09/10/04	7280
07/06/04	7950	09/13/04	6650
07/07/04	7570	09/14/04	6310
07/08/04	7300	09/15/04	7880
07/09/04	7750	09/16/04	6560
07/12/04	8080	09/17/04	7000
07/13/04	7560	09/20/04	7240
07/15/04	7380	09/21/04	5710
07/16/04	7900	09/22/04	6570
07/19/04	7150	09/23/04	4940
07/21/04	6780	09/24/04	7060
07/22/04	7700	09/26/04	4180
07/23/04	7660	09/27/04	5710
07/26/04	7170	09/28/04	5800
07/27/04	8010	09/29/04	5670
07/28/04	7520	09/30/04	6260
07/29/04	7940	10/03/04	5710
07/30/04	8100	10/04/04	5220
08/02/04	8070	10/05/04	5550
08/03/04	7670	10/06/04	3030
08/04/04	7680	10/07/04	4440
08/05/04	8400	10/10/04	5800
08/06/04	8400	10/11/04	5780
08/09/04	6980	10/12/04	5880
08/10/04	8380	10/13/04	5610
08/11/04	7120	10/14/04	5410
08/12/04	8490	10/17/04	3140
08/13/04	7760	10/18/04	4800
08/16/04	7950	10/19/04	4840
08/17/04	4160	10/20/04	5220
08/18/04	8170	10/21/04	3990
08/19/04	7810	10/24/04	5200
08/20/04	8160	10/25/04	6260
08/23/04	8270	10/26/04	5370
08/24/04	8130	10/27/04	5620
08/25/04	7320	10/28/04	2520
08/26/04	8210	10/31/04	5840
08/27/04	8070	11/01/04	6470
08/30/04	8340	11/02/04	6120
08/31/04	7440	11/03/04	5300
09/01/04	7630	11/04/04	3530
09/02/04	7620	11/07/04	6080
09/03/04	7510	11/08/04	6460
09/07/04	7710	11/09/04	6440
09/08/04	6770	11/10/04	6430
09/09/04	5960	11/11/04	6370

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
11/14/04	6300	01/05/05	6919
11/15/04	7590	01/06/05	7016
11/16/04	2590	01/07/05	6932
11/17/04	7700	01/08/05	7006
11/18/04	7520	01/09/05	6819
11/21/04	7790	01/10/05	6453
11/22/04	6400	01/11/05	4726
11/23/04	4900	01/12/05	6548
11/28/04	6530	01/13/05	4716
11/29/04	6880	01/14/05	6762
11/30/04	3415	01/15/05	7228
12/01/04	4032	01/16/05	6984
12/02/04	1789	01/17/05	5756
12/03/04	5346	01/18/05	6865
12/04/04	5737	01/19/05	4855
12/05/04	5735	01/20/05	6935
12/06/04	5759	01/21/05	6832
12/07/04	6085	01/22/05	7199
12/08/04	5805	01/23/05	6594
12/09/04	6119	01/24/05	6966
12/10/04	6540	01/25/05	6453
12/11/04	6546	01/26/05	6751
12/12/04	6172	01/27/05	6842
12/13/04	6724	01/28/05	6575
12/14/04	6813	01/29/05	6556
12/15/04	6274	01/30/05	6729
12/16/04	5042	01/31/05	6742
12/17/04	6743	02/01/05	6690
12/18/04	6905	02/02/05	6894
12/19/04	6947	02/03/05	6931
12/20/04	6187	02/04/05	4221
12/21/04	6806	02/05/05	6637
12/22/04	6679	02/06/05	6298
12/23/04	6954	02/07/05	6366
12/24/04	6945	02/08/05	6346
12/25/04	6802	02/09/05	7126
12/26/04	6552	02/10/05	4858
12/27/04	6450	02/11/05	6500
12/28/04	7284	02/12/05	7121
12/29/04	7150	02/13/05	7095
12/30/04	6921	02/14/05	6809
12/31/04	6546	02/15/05	7136
01/01/05	6615	02/16/05	6229
01/02/05	6615	02/17/05	6887
01/03/05	6589	02/18/05	5998
01/04/05	6614	02/19/05	5952

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
02/20/05	6725	04/07/05	6329
02/21/05	6029	04/08/05	5892
02/22/05	5969	04/09/05	7188
02/23/05	4942	04/10/05	6178
02/24/05	5026	04/11/05	6590
02/25/05	5940	04/12/05	5950
02/26/05	6115	04/13/05	5759
02/27/05	5921	04/14/05	5957
02/28/05	5447	04/15/05	5817
03/01/05	5852	04/16/05	6287
03/02/05	5708	04/17/05	5882
03/03/05	6792	04/18/05	6161
03/04/05	6725	04/19/05	4675
03/05/05	7070	04/20/05	6006
03/06/05	6330	04/21/05	6228
03/07/05	6898	04/22/05	5687
03/08/05	6967	04/23/05	5835
03/09/05	5755	04/24/05	5986
03/10/05	5616	04/25/05	6008
03/11/05	6524	04/26/05	6243
03/12/05	6603	04/27/05	5549
03/13/05	7035	04/28/05	6576
03/14/05	6646	04/29/05	7157
03/15/05	5826	04/30/05	7065
03/16/05	5305	05/01/05	6411
03/17/05	6111	05/02/05	7471
03/18/05	6161	05/03/05	7619
03/19/05	6429	05/04/05	7508
03/20/05	5710	05/05/05	6999
03/21/05	6205	05/06/05	6939
03/22/05	5921	05/07/05	7471
03/23/05	5991	05/08/05	7229
03/24/05	6042	05/09/05	7127
03/25/05	4806	05/10/05	6856
03/26/05	7315	05/11/05	6741
03/27/05	7299	05/12/05	6757
03/28/05	6408	05/13/05	7209
03/29/05	5264	05/14/05	7409
03/30/05	5452	05/15/05	7537
03/31/05	5981	05/16/05	5657
04/01/05	6876	05/17/05	5798
04/02/05	7039	05/18/05	7735
04/03/05	6973	05/19/05	7168
04/04/05	6750	05/20/05	7168
04/05/05	7105	05/21/05	6633
04/06/05	7015	05/22/05	4127

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
05/23/05	3930	07/08/05	7726
05/24/05	3886	07/09/05	7517
05/25/05	3764	07/10/05	7635
05/26/05	3755	07/11/05	7761
05/27/05	3720	07/12/05	7782
05/28/05	3736	07/13/05	7838
05/29/05	3698	07/14/05	7702
05/30/05	3792	07/15/05	7631
05/31/05	3807	07/16/05	7284
06/01/05	3732	07/17/05	7357
06/02/05	3660	07/18/05	7413
06/03/05	3626	07/19/05	6678
06/04/05	3547	07/20/05	5403
06/05/05	3530	07/21/05	5652
06/06/05	3549	07/22/05	5973
06/07/05	3806	07/23/05	5687
06/08/05	4555	07/24/05	5448
06/09/05	7752	07/25/05	5943
06/10/05	7363	07/26/05	5651
06/11/05	6811	07/27/05	5426
06/12/05	7963	07/28/05	5554
06/13/05	7819	07/29/05	6235
06/14/05	7708	07/30/05	5569
06/15/05	7798	07/31/05	4290
06/16/05	7460	08/01/05	2873
06/17/05	7947	08/02/05	2856
06/18/05	7950	08/03/05	2727
06/19/05	7826	08/04/05	5068
06/20/05	7197	08/05/05	5329
06/21/05	7472	08/06/05	5256
06/22/05	7716	08/07/05	5633
06/23/05	7248	08/08/05	5772
06/24/05	7938	08/09/05	5864
06/25/05	7953	08/10/05	6001
06/26/05	5672	08/11/05	5821
06/27/05	6622	08/12/05	5994
06/28/05	5428	08/13/05	6414
06/29/05	7589	08/14/05	6433
06/30/05	7893	08/15/05	6415
07/01/05	7747	08/16/05	6281
07/02/05	7570	08/17/05	5854
07/03/05	7790	08/18/05	6331
07/04/05	7808	08/19/05	6032
07/05/05	7722	08/20/05	5843
07/06/05	7850	08/21/05	6022
07/07/05	6377	08/22/05	5427

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
08/23/05	4942	10/08/05	6530
08/24/05	5678	10/09/05	7146
08/25/05	6479	10/10/05	7414
08/26/05	6119	10/11/05	7720
08/27/05	6897	10/12/05	7018
08/28/05	6793	10/13/05	7085
08/29/05	6106	10/14/05	7010
08/30/05	6997	10/15/05	6914
08/31/05	7258	10/16/05	6218
09/01/05	7033	10/17/05	6332
09/02/05	6702	10/18/05	6945
09/03/05	6613	10/19/05	6029
09/04/05	5168	10/20/05	6689
09/05/05	6634	10/21/05	7291
09/06/05	6519	10/22/05	7414
09/07/05	6809	10/23/05	7570
09/08/05	6888	10/24/05	7438
09/09/05	7432	10/25/05	7518
09/10/05	7118	10/26/05	7581
09/11/05	7156	10/27/05	7283
09/12/05	6929	10/28/05	7029
09/13/05	7270	10/29/05	7442
09/14/05	6483	10/30/05	7223
09/15/05	7044	10/31/05	6863
09/16/05	7081	11/01/05	6851
09/17/05	6780	11/02/05	6707
09/18/05	6929	11/03/05	6040
09/19/05	6827	11/04/05	6954
09/20/05	6884	11/05/05	6807
09/21/05	6629	11/06/05	6727
09/22/05	6376	11/07/05	6499
09/23/05	5634	11/08/05	6250
09/24/05	6428	11/09/05	6587
09/25/05	6182	11/10/05	6971
09/26/05	6636	11/11/05	6903
09/27/05	5923	11/12/05	7034
09/28/05	5482	11/13/05	6813
09/29/05	5612	11/14/05	7068
09/30/05	6285	11/15/05	7237
10/01/05	6811	11/16/05	4430
10/02/05	7312	11/17/05	7868
10/03/05	7373	11/18/05	7580
10/04/05	7287	11/19/05	7698
10/05/05	7357	11/20/05	7348
10/06/05	7312	11/21/05	7463
10/07/05	3578	11/22/05	7392

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
11/23/05	7492	01/09/06	6365
11/24/05	7538	01/10/06	6527
11/25/05	7339	01/11/06	6460
11/26/05	7301	01/12/06	6058
11/27/05	7102	01/13/06	6665
11/28/05	7002	01/14/06	6737
11/29/05	7213	01/15/06	6702
12/01/05	6735	01/16/06	6510
12/02/05	7346	01/17/06	6617
12/03/05	7395	01/18/06	6618
12/04/05	7180	01/19/06	6675
12/05/05	7179	01/20/06	6864
12/06/05	7102	01/21/06	6681
12/07/05	6998	01/22/06	6759
12/08/05	6857	01/23/06	6613
12/09/05	6487	01/24/06	6785
12/10/05	6448	01/25/06	6777
12/11/05	6228	01/26/06	6956
12/12/05	6111	01/27/06	6456
12/13/05	6336	01/28/06	6866
12/14/05	6237	01/29/06	6744
12/15/05	6492	01/30/06	6913
12/16/05	6559	01/31/06	6444
12/17/05	6646	02/01/06	5234
12/18/05	6740	02/02/06	5685
12/19/05	6692	02/03/06	5874
12/20/05	6796	02/04/06	6433
12/21/05	6714	02/05/06	6681
12/22/05	6612	02/06/06	6552
12/23/05	6320	02/07/06	6409
12/24/05	6787	02/08/06	6373
12/25/05	6673	02/09/06	6170
12/26/05	5775	02/10/06	6371
12/27/05	5950	02/11/06	5186
12/28/05	5980	02/12/06	5643
12/29/05	6060	02/13/06	5943
12/30/05	4616	02/14/06	5997
12/31/05	6061	02/15/06	3801
01/01/06	6087	02/16/06	5017
01/02/06	5433	02/17/06	6545
01/03/06	6105	02/18/06	5905
01/04/06	5894	02/19/06	6298
01/05/06	5854	02/20/06	5921
01/06/06	5485	02/21/06	5774
01/07/06	4664	02/22/06	6513
01/08/06	5811	02/23/06	3978

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
02/24/06	5486	04/11/06	6375
02/25/06	5770	04/12/06	6328
02/26/06	5484	04/13/06	6132
02/27/06	5887	04/14/06	6032
02/28/06	6224	04/15/06	6824
03/01/06	5858	04/16/06	6442
03/02/06	5595	04/17/06	6599
03/03/06	5280	04/18/06	6334
03/04/06	4691	04/19/06	6377
03/05/06	4996	04/20/06	6795
03/06/06	5158	04/21/06	6756
03/07/06	5465	04/22/06	6782
03/08/06	5462	04/23/06	6822
03/09/06	5507	04/24/06	6580
03/10/06	5489	04/25/06	6721
03/11/06	5973	04/26/06	6905
03/12/06	5851	04/27/06	7435
03/13/06	5439	04/28/06	7809
03/14/06	6100	04/29/06	8017
03/15/06	6219	04/30/06	7739
03/16/06	5707	05/01/06	7893
03/17/06	4839	05/02/06	7573
03/18/06	5876	05/03/06	7330
03/19/06	6318	05/04/06	7949
03/20/06	4163	05/05/06	7692
03/21/06	4171	05/06/06	8174
03/22/06	4343	05/07/06	8210
03/23/06	3749	05/08/06	7110
03/24/06	4925	05/09/06	7729
03/25/06	5366	05/10/06	8075
03/26/06	5307	05/11/06	7616
03/27/06	5256	05/12/06	7860
03/28/06	5745	05/13/06	7940
03/29/06	5161	05/14/06	7784
03/30/06	5267	05/15/06	8141
03/31/06	6263	05/16/06	8022
04/01/06	6408	05/17/06	7963
04/02/06	6330	05/18/06	7939
04/03/06	6690	05/19/06	7767
04/04/06	7205	05/20/06	7999
04/05/06	6697	05/21/06	7796
04/06/06	6300	05/22/06	7701
04/07/06	7027	05/23/06	7912
04/08/06	6440	05/24/06	7974
04/09/06	6301	05/25/06	7875
04/10/06	6352	05/26/06	7992

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
05/27/06	7894	07/12/06	7439
05/28/06	7911	07/13/06	8092
05/29/06	8086	07/14/06	8051
05/30/06	7727	07/15/06	8168
05/31/06	7966	07/16/06	8101
06/01/06	7954	07/17/06	8036
06/02/06	7959	07/18/06	8089
06/03/06	8092	07/19/06	7997
06/04/06	7973	07/20/06	5000
06/05/06	7796	07/21/06	7311
06/06/06	7283	07/22/06	7458
06/07/06	7896	07/23/06	7477
06/08/06	7928	07/24/06	7644
06/09/06	8051	07/25/06	7819
06/10/06	7638	07/26/06	7911
06/11/06	8050	07/27/06	8237
06/12/06	8012	07/28/06	8142
06/13/06	7999	07/29/06	8044
06/14/06	7662	07/30/06	8164
06/15/06	7891	07/31/06	8052
06/16/06	8059	08/01/06	8113
06/17/06	8009	08/02/06	8057
06/18/06	8107	08/03/06	8065
06/19/06	8092	08/04/06	8033
06/20/06	8079	08/05/06	8187
06/21/06	7914	08/06/06	8080
06/22/06	7895	08/07/06	8048
06/23/06	7954	08/08/06	8191
06/24/06	7968	08/09/06	8057
06/25/06	7920	08/10/06	8156
06/26/06	7894	08/11/06	7970
06/27/06	7926	08/12/06	7898
06/28/06	8041	08/13/06	8173
06/29/06	7943	08/14/06	8021
06/30/06	7872	08/15/06	8129
07/01/06	7949	08/16/06	7397
07/02/06	7948	08/17/06	7214
07/03/06	7948	08/18/06	7888
07/04/06	7940	08/19/06	7501
07/05/06	7610	08/20/06	7552
07/06/06	8022	08/21/06	7863
07/07/06	8185	08/22/06	7664
07/08/06	8033	08/23/06	7727
07/09/06	8023	08/24/06	7704
07/10/06	8098	08/25/06	7643
07/11/06	7966	08/26/06	7729

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
08/27/06	7531	10/12/06	7233
08/28/06	7820	10/13/06	8133
08/29/06	8211	10/14/06	7863
08/30/06	7643	10/15/06	7730
08/31/06	7711	10/16/06	8091
09/01/06	7885	10/17/06	8200
09/02/06	7844	10/18/06	8035
09/03/06	7957	10/19/06	8099
09/04/06	7892	10/20/06	8113
09/05/06	7793	10/21/06	8019
09/06/06	7884	10/22/06	5986
09/07/06	7651	10/23/06	8051
09/08/06	7518	10/24/06	6222
09/09/06	7827	10/25/06	7144
09/10/06	7761	10/26/06	7481
09/11/06	7947	10/27/06	7504
09/12/06	8097	10/28/06	8201
09/13/06	7855	10/29/06	7511
09/14/06	7950	10/30/06	7238
09/15/06	7989	10/31/06	5942
09/16/06	8175	11/01/06	8110
09/17/06	7960	11/02/06	7201
09/18/06	7552	11/03/06	6905
09/19/06	7820	11/04/06	6827
09/20/06	7910	11/05/06	7164
09/21/06	7596	11/06/06	7068
09/22/06	7673	11/07/06	6893
09/23/06	7808	11/08/06	7159
09/24/06	7837	11/09/06	7496
09/25/06	7720	11/10/06	7757
09/26/06	7301	11/11/06	7612
09/27/06	7072	11/12/06	7320
09/28/06	7509	11/13/06	7128
09/29/06	7493	11/14/06	7673
09/30/06	7321	11/15/06	8338
10/01/06	7984	11/16/06	7438
10/02/06	5808	11/17/06	6365
10/03/06	5852	11/18/06	7985
10/04/06	5777	11/19/06	7860
10/05/06	5183	11/20/06	7587
10/06/06	5212	11/21/06	7807
10/07/06	7460	11/22/06	7832
10/08/06	7877	11/23/06	7667
10/09/06	8191	11/24/06	6630
10/10/06	8216	11/25/06	7013
10/11/06	7767	11/26/06	7141

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
11/27/06	5318	01/12/07	7801
11/28/06	7430	01/13/07	7772
11/29/06	7570	01/14/07	7807
11/30/06	7534	01/15/07	7880
12/01/06	7874	01/16/07	8107
12/02/06	7143	01/17/07	8101
12/03/06	7822	01/18/07	8202
12/04/06	7908	01/19/07	7985
12/05/06	8036	01/20/07	8108
12/06/06	7895	01/21/07	7818
12/07/06	8017	01/22/07	7934
12/08/06	7465	01/23/07	7905
12/09/06	8083	01/24/07	8143
12/10/06	8209	01/25/07	7993
12/11/06	8265	01/26/07	8141
12/12/06	6333	01/27/07	7912
12/13/06	8151	01/28/07	7886
12/14/06	8205	01/29/07	7938
12/15/06	7668	01/30/07	7871
12/16/06	7901	01/31/07	8172
12/17/06	7942	02/01/07	8119
12/18/06	8023	02/02/07	7983
12/19/06	7485	02/03/07	8080
12/20/06	8108	02/04/07	7855
12/21/06	8085	02/05/07	7858
12/22/06	7936	02/06/07	7708
12/23/06	7748	02/07/07	7988
12/24/06	7800	02/08/07	8212
12/25/06	7934	02/09/07	8167
12/26/06	7873	02/10/07	7989
12/27/06	7999	02/11/07	8137
12/28/06	8146	02/12/07	7950
12/29/06	8076	02/13/07	7901
12/30/06	8109	02/14/07	7754
12/31/06	8139	02/15/07	8045
01/01/07	7700	02/16/07	7926
01/02/07	8103	02/17/07	7874
01/03/07	7825	02/18/07	7997
01/04/07	7873	02/19/07	7617
01/05/07	7866	02/20/07	7978
01/06/07	7693	02/21/07	7858
01/07/07	7833	02/22/07	7765
01/08/07	7814	02/23/07	8015
01/09/07	7672	02/24/07	7808
01/10/07	7876	02/25/07	7958
01/11/07	7875	02/26/07	7923

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
02/27/07	7642	04/14/07	7035
02/28/07	7902	04/15/07	6027
03/01/07	7842	04/16/07	6088
03/02/07	7756	04/17/07	7205
03/03/07	6978	04/18/07	6552
03/04/07	5931	04/19/07	7080
03/05/07	7509	04/20/07	6050
03/06/07	7874	04/21/07	6166
03/07/07	7943	04/22/07	5595
03/08/07	7741	04/23/07	7173
03/09/07	6941	04/24/07	5753
03/10/07	8039	04/25/07	6177
03/11/07	7982	04/26/07	6856
03/12/07	7337	04/27/07	6917
03/13/07	7611	04/28/07	7091
03/14/07	7958	04/29/07	7112
03/15/07	7863	04/30/07	7298
03/16/07	8086	05/01/07	5434
03/17/07	7686	05/02/07	7019
03/18/07	8137	05/03/07	7043
03/19/07	8110	05/04/07	7311
03/20/07	7663	05/05/07	7160
03/21/07	7931	05/06/07	7260
03/22/07	7903	05/07/07	6577
03/23/07	7980	05/08/07	7787
03/24/07	7950	05/09/07	8064
03/25/07	7901	05/10/07	7890
03/26/07	7197	05/11/07	8123
03/27/07	8159	05/12/07	8190
03/28/07	7942	05/13/07	8186
03/29/07	8115	05/14/07	8136
03/30/07	8091	05/15/07	8358
03/31/07	8110	05/16/07	8290
04/01/07	7741	05/17/07	8211
04/02/07	8166	05/18/07	8088
04/03/07	8048	05/19/07	8179
04/04/07	8030	05/20/07	8273
04/05/07	7615	05/21/07	8145
04/06/07	8060	05/22/07	8328
04/07/07	7932	05/23/07	7911
04/08/07	6333	05/24/07	8269
04/09/07	6153	05/25/07	8167
04/10/07	8198	05/26/07	8258
04/11/07	7523	05/27/07	7740
04/12/07	7143	05/28/07	7070
04/13/07	6326	05/29/07	7846

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
05/30/07	8192	07/15/07	8179
05/31/07	8166	07/16/07	8234
06/01/07	8173	07/17/07	8159
06/02/07	8090	07/18/07	8209
06/03/07	8043	07/19/07	8165
06/04/07	8136	07/20/07	8098
06/05/07	8165	07/21/07	8205
06/06/07	7863	07/22/07	8171
06/07/07	7647	07/23/07	8176
06/08/07	8140	07/24/07	8210
06/09/07	8020	07/25/07	8255
06/10/07	7789	07/26/07	8119
06/11/07	7780	07/27/07	8143
06/12/07	7852	07/28/07	8273
06/13/07	8131	07/29/07	8193
06/14/07	7228	07/30/07	8162
06/15/07	8304	07/31/07	7379
06/16/07	8220	08/01/07	8097
06/17/07	8237	08/02/07	8135
06/18/07	8225	08/03/07	8186
06/19/07	8126	08/04/07	8254
06/20/07	8227	08/05/07	8209
06/21/07	7967	08/06/07	8281
06/22/07	6460	08/07/07	8258
06/23/07	8148	08/08/07	8152
06/24/07	8221	08/09/07	7980
06/25/07	7885	08/10/07	8171
06/26/07	8181	08/11/07	8101
06/27/07	8083	08/12/07	8156
06/28/07	8105	08/13/07	8174
06/29/07	7807	08/14/07	8185
06/30/07	8113	08/15/07	8083
07/01/07	7524	08/16/07	8115
07/02/07	7538	08/17/07	8126
07/03/07	7644	08/18/07	8121
07/04/07	8045	08/19/07	8234
07/05/07	8073	08/20/07	8142
07/06/07	8150	08/21/07	8112
07/07/07	7895	08/22/07	8134
07/08/07	7743	08/23/07	8157
07/09/07	7741	08/24/07	8256
07/10/07	7667	08/25/07	8118
07/11/07	7655	08/26/07	8126
07/12/07	8138	08/27/07	8239
07/13/07	7948	08/28/07	8153
07/14/07	8210	08/29/07	8245

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
08/30/07	8236	10/15/07	8079
08/31/07	8137	10/16/07	7412
09/01/07	8118	10/17/07	8508
09/02/07	8049	10/18/07	8497
09/03/07	8254	10/19/07	8040
09/04/07	8196	10/20/07	7905
09/05/07	8140	10/21/07	8120
09/06/07	8306	10/22/07	8357
09/07/07	8265	10/23/07	8218
09/08/07	8313	10/24/07	8330
09/09/07	8339	10/25/07	8375
09/10/07	8261	10/26/07	8311
09/11/07	8299	10/27/07	8331
09/12/07	8302	10/28/07	8267
09/13/07	8222	10/29/07	8367
09/14/07	8339	10/30/07	8228
09/15/07	8176	10/31/07	8227
09/16/07	8233	11/01/07	8076
09/17/07	8324	11/02/07	8220
09/18/07	8342	11/03/07	7687
09/19/07	8260	11/04/07	8110
09/20/07	8307	11/05/07	8036
09/21/07	8348	11/06/07	7927
09/22/07	8351	11/07/07	7975
09/23/07	8110	11/08/07	7700
09/24/07	8360	11/09/07	7439
09/25/07	8267	11/10/07	7972
09/26/07	8138	11/11/07	8098
09/27/07	8363	11/12/07	8127
09/28/07	8307	11/13/07	8004
09/29/07	8390	11/14/07	7753
09/30/07	8509	11/15/07	7775
10/01/07	8288	11/16/07	7536
10/02/07	8276	11/17/07	7973
10/03/07	8015	11/18/07	7521
10/04/07	8276	11/19/07	7556
10/05/07	8494	11/20/07	7994
10/06/07	8537	11/21/07	8057
10/07/07	8536	11/22/07	7788
10/08/07	8173	11/23/07	7860
10/09/07	8417	11/24/07	8144
10/10/07	8505	11/25/07	8224
10/11/07	8285	11/26/07	8190
10/12/07	8393	11/27/07	8142
10/13/07	8323	11/28/07	8219
10/14/07	8538	11/29/07	8202

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
11/30/07	8165	01/15/08	8043
12/01/07	8019	01/16/08	8198
12/02/07	8175	01/17/08	7761
12/03/07	8051	01/18/08	8137
12/04/07	7893	01/19/08	8194
12/05/07	8136	01/20/08	8087
12/06/07	7930	01/21/08	8047
12/07/07	7927	01/22/08	5938
12/08/07	7958	01/23/08	8199
12/09/07	7814	01/24/08	8130
12/10/07	7915	01/25/08	8255
12/11/07	8074	01/26/08	8069
12/12/07	7954	01/27/08	8093
12/13/07	7767	01/28/08	8141
12/14/07	7521	01/29/08	7691
12/15/07	7274	01/30/08	8107
12/16/07	7345	01/31/08	8029
12/17/07	7107	02/01/08	8205
12/18/07	7761	02/02/08	8053
12/19/07	8052	02/03/08	8145
12/20/07	7800	02/04/08	7928
12/21/07	7997	02/05/08	8050
12/22/07	8102	02/06/08	8146
12/23/07	8052	02/07/08	6308
12/24/07	8159	02/08/08	8237
12/25/07	8282	02/09/08	8062
12/26/07	8111	02/10/08	8005
12/27/07	8170	02/11/08	8147
12/28/07	8042	02/12/08	8055
12/29/07	8067	02/13/08	7991
12/30/07	7952	02/14/08	7868
12/31/07	7893	02/15/08	8079
01/01/08	7909	02/16/08	8247
01/02/08	8191	02/17/08	8104
01/03/08	6845	02/18/08	8155
01/04/08	8151	02/19/08	8102
01/05/08	8101	02/20/08	8112
01/06/08	8032	02/21/08	8160
01/07/08	7847	02/22/08	8053
01/08/08	8061	02/23/08	8124
01/09/08	6725	02/24/08	8044
01/10/08	7882	02/25/08	8065
01/11/08	7866	02/26/08	8153
01/12/08	8069	02/27/08	8110
01/13/08	8022	02/28/08	7725
01/14/08	8280	02/29/08	8063

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitation : 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambient : 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
03/01/08	8011	04/16/08	7700
03/02/08	7945	04/17/08	7190
03/03/08	8022	04/18/08	7501
03/04/08	8184	04/19/08	7764
03/05/08	8017	04/20/08	7581
03/06/08	7898	04/21/08	7809
03/07/08	7028	04/22/08	7640
03/08/08	7600	04/23/08	8124
03/09/08	7931	04/24/08	7571
03/10/08	7684	04/25/08	8170
03/11/08	6797	04/26/08	8211
03/12/08	6860	04/27/08	7824
03/13/08	6397	04/28/08	6845
03/14/08	6966	04/29/08	8041
03/15/08	7080	04/30/08	7717
03/16/08	8124	05/01/08	7719
03/17/08	6818	05/02/08	6799
03/18/08	7559	05/03/08	6169
03/19/08	7897	05/04/08	7042
03/20/08	7463	05/05/08	6835
03/21/08	4828	05/06/08	7005
03/22/08	7959	05/07/08	6661
03/23/08	8180	05/08/08	6976
03/24/08	8095	05/09/08	7430
03/25/08	8240	05/10/08	8147
03/26/08	8130	05/11/08	8052
03/27/08	7795	05/12/08	7918
03/28/08	8030	05/13/08	8136
03/29/08	7856	05/14/08	8019
03/30/08	7928	05/15/08	8074
03/31/08	7719	05/16/08	8052
04/01/08	6823	05/17/08	8225
04/02/08	5776	05/18/08	8122
04/03/08	7983	05/19/08	7976
04/04/08	7415	05/20/08	8083
04/05/08	7773	05/21/08	7994
04/06/08	7853	05/22/08	8014
04/07/08	7343	05/23/08	7861
04/08/08	7022	05/24/08	6223
04/09/08	7544	05/25/08	5778
04/10/08	7583	05/26/08	7291
04/11/08	7769	05/27/08	8000
04/12/08	7966	05/28/08	8089
04/13/08	7699	05/29/08	8154
04/14/08	7685	05/30/08	8192
04/15/08	7558	05/31/08	7933

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
06/01/08	8015	07/17/08	8024
06/02/08	8066	07/18/08	8106
06/03/08	7933	07/19/08	6910
06/04/08	8032	07/21/08	7320
06/05/08	8094	07/25/08	8121
06/06/08	8188	07/26/08	8091
06/07/08	8211	07/27/08	8073
06/08/08	8145	07/28/08	7912
06/09/08	8071	07/29/08	7819
06/10/08	8110	07/30/08	8003
06/11/08	7879	07/31/08	8069
06/12/08	7786	08/01/08	7990
06/13/08	7628	08/02/08	7960
06/14/08	8086	08/03/08	8088
06/15/08	8201	08/04/08	7833
06/16/08	8246	08/05/08	8180
06/17/08	8209	08/06/08	8011
06/18/08	8060	08/07/08	8093
06/19/08	7862	08/08/08	8189
06/20/08	8133	08/09/08	8157
06/21/08	8025	08/10/08	8175
06/22/08	7970	08/11/08	8080
06/23/08	7985	08/12/08	8219
06/24/08	8062	08/13/08	7942
06/25/08	8279	08/14/08	8151
06/26/08	8013	08/15/08	8197
06/27/08	8069	08/16/08	7850
06/28/08	8028	08/17/08	8105
06/29/08	8184	08/18/08	7890
06/30/08	7968	08/19/08	8237
07/01/08	7998	08/20/08	8316
07/02/08	7310	08/21/08	8163
07/03/08	7911	08/22/08	7890
07/04/08	8034	08/23/08	8311
07/05/08	7943	08/24/08	8086
07/06/08	7990	08/25/08	8003
07/07/08	8031	08/26/08	7968
07/08/08	7870	08/27/08	7999
07/09/08	7570	08/28/08	7884
07/10/08	7933	08/29/08	8015
07/11/08	7960	08/30/08	7836
07/12/08	7535	08/31/08	7584
07/13/08	7909	09/01/08	7812
07/14/08	7476	09/02/08	7729
07/15/08	8094	09/03/08	8115
07/16/08	8072	09/04/08	2957

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
09/05/08	8172	10/21/08	7195
09/06/08	7739	10/22/08	6319
09/07/08	6870	10/23/08	6475
09/08/08	8035	10/24/08	6174
09/09/08	8030	10/25/08	6690
09/10/08	8059	10/26/08	5466
09/11/08	6464	10/27/08	4077
09/12/08	8199	10/28/08	3967
09/13/08	8117	10/29/08	6267
09/14/08	8130	10/30/08	6127
09/15/08	5665	10/31/08	5898
09/16/08	7522	11/01/08	5728
09/17/08	7743	11/02/08	5286
09/18/08	7476	11/03/08	5184
09/19/08	7404	11/04/08	5083
09/20/08	6949	11/05/08	5135
09/21/08	6306	11/06/08	5288
09/22/08	6204	11/07/08	5713
09/23/08	6523	11/08/08	5189
09/24/08	6111	11/09/08	4960
09/25/08	6448	11/10/08	4784
09/26/08	6415	11/11/08	5518
09/27/08	7324	11/12/08	5432
09/28/08	7066	11/13/08	5697
09/29/08	5648	11/14/08	4848
09/30/08	6822	11/15/08	4794
10/01/08	6507	11/16/08	4589
10/02/08	7146	11/17/08	4853
10/03/08	6912	11/18/08	4417
10/04/08	6381	11/20/08	2628
10/05/08	6348	11/21/08	4716
10/06/08	6723	11/22/08	4662
10/07/08	6497	11/23/08	4693
10/08/08	6854	11/24/08	5047
10/09/08	6759	11/25/08	4415
10/10/08	6910	11/26/08	5436
10/11/08	6347	11/27/08	5268
10/12/08	6632	11/28/08	5116
10/13/08	7164	11/29/08	5288
10/14/08	5378	11/30/08	5746
10/15/08	6885	12/01/08	4999
10/16/08	5631	12/02/08	5728
10/17/08	7127	12/03/08	5095
10/18/08	6557	12/04/08	5627
10/19/08	6222	12/05/08	5547
10/20/08	7042	12/06/08	5097

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitation : 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambient : 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
12/07/08	5280	01/22/09	5232
12/08/08	4917	01/23/09	5513
12/09/08	5106	01/24/09	4889
12/10/08	5361	01/25/09	4938
12/11/08	5539	01/26/09	4989
12/12/08	5200	01/27/09	5023
12/13/08	5111	01/28/09	5478
12/14/08	5170	01/29/09	5078
12/15/08	5308	01/30/09	5723
12/16/08	4747	01/31/09	5302
12/17/08	4990	02/01/09	3027
12/18/08	4227	02/02/09	5502
12/19/08	5239	02/03/09	6115
12/20/08	2476	02/04/09	6460
12/21/08	6800	02/05/09	6212
12/22/08	7102	02/06/09	6076
12/23/08	7059	02/07/09	5718
12/24/08	6262	02/08/09	6480
12/25/08	5281	02/09/09	6599
12/26/08	5223	02/10/09	7313
12/27/08	5174	02/11/09	6890
12/28/08	4162	02/12/09	7391
12/29/08	5633	02/13/09	6851
12/30/08	5581	02/14/09	5693
12/31/08	6208	02/15/09	5310
01/01/09	6807	02/16/09	5250
01/02/09	3488	02/17/09	5597
01/03/09	4226	02/18/09	4512
01/04/09	5672	02/19/09	6459
01/05/09	5919	02/20/09	6932
01/06/09	5585	02/21/09	7227
01/07/09	4572	02/22/09	7044
01/08/09	5268	02/23/09	6582
01/09/09	5242	02/24/09	7193
01/10/09	5059	02/25/09	7281
01/11/09	5393	02/26/09	6958
01/12/09	5157	02/27/09	6946
01/13/09	5042	02/28/09	5175
01/14/09	4932	03/01/09	7132
01/15/09	5321	03/02/09	6865
01/16/09	5356	03/03/09	6779
01/17/09	6175	03/04/09	6626
01/18/09	5498	03/05/09	6384
01/19/09	4587	03/06/09	5839
01/20/09	5237	03/07/09	5849
01/21/09	5634	03/08/09	5255

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
03/09/09	5224	04/24/09	2422
03/10/09	5510	04/25/09	2433
03/11/09	5621	04/26/09	7134
03/12/09	5593	04/27/09	7942
03/13/09	5793	04/28/09	7325
03/14/09	5858	04/29/09	7442
03/15/09	6260	04/30/09	6786
03/16/09	5861	05/01/09	7245
03/17/09	6325	05/02/09	6643
03/18/09	6031	05/03/09	6630
03/19/09	6500	05/04/09	7000
03/20/09	3898	05/05/09	6096
03/21/09	4850	05/06/09	5637
03/22/09	5394	05/07/09	7473
03/23/09	5756	05/08/09	7154
03/24/09	6078	05/09/09	6393
03/25/09	4879	05/10/09	6975
03/26/09	5339	05/11/09	6510
03/27/09	4917	05/12/09	5925
03/28/09	5828	05/13/09	6555
03/29/09	6163	05/14/09	6391
03/30/09	5565	05/15/09	5207
03/31/09	5207	05/16/09	4801
04/01/09	5021	05/17/09	5851
04/02/09	5157	05/18/09	6407
04/03/09	4947	05/19/09	5918
04/04/09	4457	05/20/09	6486
04/05/09	5694	05/21/09	6492
04/06/09	5481	05/22/09	6708
04/07/09	5463	05/23/09	6373
04/08/09	5589	05/24/09	5912
04/09/09	6420	05/25/09	6101
04/10/09	6047	05/26/09	5055
04/11/09	6294	05/27/09	5123
04/12/09	6122	05/28/09	5523
04/13/09	6441	05/29/09	5662
04/14/09	6382	05/30/09	5231
04/15/09	6462	05/31/09	5724
04/16/09	5888	06/01/09	6250
04/17/09	5200	06/02/09	6153
04/18/09	4887	06/03/09	5742
04/19/09	6062	06/04/09	6596
04/20/09	3069	06/05/09	6627
04/21/09	2805	06/06/09	4920
04/22/09	3122	06/07/09	6412
04/23/09	2995	06/08/09	6892

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
06/09/09	5526	07/25/09	5839
06/10/09	5961	07/26/09	5450
06/11/09	7054	07/27/09	5341
06/12/09	6793	07/28/09	5322
06/13/09	6958	07/29/09	5417
06/14/09	6797	07/30/09	4919
06/15/09	6287	07/31/09	5193
06/16/09	6547	08/01/09	5120
06/17/09	6798	08/02/09	4709
06/18/09	5493	08/03/09	4660
06/19/09	7061	08/04/09	4417
06/20/09	6799	08/05/09	4309
06/21/09	4719	08/06/09	4541
06/22/09	6101	08/07/09	4842
06/23/09	6931	08/08/09	4882
06/24/09	6422	08/09/09	4814
06/25/09	6992	08/10/09	5200
06/26/09	6535	08/11/09	4819
06/27/09	6412	08/12/09	4631
06/28/09	6475	08/13/09	6361
06/29/09	5910	08/14/09	4369
06/30/09	6395	08/15/09	3885
07/01/09	6436	08/16/09	5881
07/02/09	6257	08/17/09	5864
07/03/09	6130	08/18/09	5840
07/04/09	6412	08/19/09	5869
07/05/09	6479	08/20/09	5136
07/06/09	6828	08/22/09	3104
07/07/09	6930	08/23/09	3104
07/08/09	6543	08/24/09	4183
07/09/09	6832	08/27/09	5231
07/10/09	5974	08/28/09	3843
07/11/09	5656	08/29/09	5067
07/12/09	6117	08/30/09	5170
07/13/09	6166	08/31/09	5140
07/14/09	6671	09/01/09	5116
07/15/09	6883	09/02/09	5251
07/16/09	6860	09/03/09	4609
07/17/09	6404	09/04/09	4789
07/18/09	6398	09/05/09	4957
07/19/09	6142	09/06/09	3867
07/20/09	5807	09/07/09	4429
07/21/09	5634	09/08/09	4368
07/22/09	4865	09/09/09	4539
07/23/09	4449	09/10/09	4696
07/24/09	4832	09/11/09	4390

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
09/12/09	4539	10/28/09	6143
09/13/09	4189	10/29/09	5585
09/14/09	3931	10/30/09	5486
09/15/09	4185	10/31/09	5391
09/16/09	4477	11/01/09	4762
09/17/09	4625	11/02/09	5422
09/18/09	4525	11/03/09	5169
09/19/09	4855	11/04/09	4296
09/20/09	4580	11/05/09	5257
09/21/09	4694	11/06/09	4762
09/22/09	4758	11/07/09	5062
09/23/09	4876	11/08/09	5300
09/24/09	4678	11/09/09	4286
09/25/09	4547	11/10/09	4377
09/26/09	4952	11/11/09	4816
09/27/09	4894	11/12/09	4854
09/28/09	4441	11/13/09	5026
09/29/09	4290	11/14/09	5682
09/30/09	4404	11/15/09	5672
10/01/09	3815	11/16/09	5635
10/02/09	3802	11/17/09	5980
10/03/09	2958	11/18/09	5741
10/04/09	3787	11/19/09	5036
10/05/09	3494	11/20/09	5115
10/06/09	3510	11/21/09	5107
10/07/09	4778	11/22/09	5314
10/08/09	5038	11/23/09	5069
10/09/09	4736	11/24/09	5157
10/10/09	5284	11/25/09	5752
10/11/09	6361	11/26/09	6332
10/12/09	5223	11/27/09	5435
10/13/09	5506	11/28/09	6365
10/14/09	5308	11/29/09	6066
10/15/09	5084	11/30/09	6274
10/16/09	4913	12/01/09	5404
10/17/09	4567	12/02/09	6270
10/18/09	3265	12/03/09	5772
10/19/09	2702	12/04/09	5892
10/20/09	3032	12/05/09	5432
10/21/09	2671	12/06/09	6136
10/22/09	3361	12/07/09	4032
10/23/09	2831	12/08/09	5306
10/24/09	1842	12/09/09	6770
10/25/09	1927	12/10/09	7192
10/26/09	4701	12/11/09	6920
10/27/09	5905	12/12/09	7197

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
12/13/09	7233	01/28/10	5155
12/14/09	6619	01/29/10	5964
12/15/09	6518	01/30/10	5492
12/16/09	6382	01/31/10	5542
12/17/09	6919	02/01/10	4324
12/18/09	6977	02/02/10	5150
12/19/09	5808	02/03/10	6032
12/20/09	6160	02/04/10	5907
12/21/09	6168	02/05/10	6031
12/22/09	6846	02/06/10	5692
12/23/09	5217	02/07/10	6324
12/24/09	7345	02/08/10	4953
12/25/09	6897	02/09/10	5947
12/26/09	7101	02/10/10	5505
12/27/09	7099	02/11/10	5608
12/28/09	6228	02/12/10	5782
12/29/09	4612	02/13/10	5668
12/30/09	5062	02/14/10	5047
12/31/09	7548	02/15/10	3974
01/01/10	7277	02/16/10	5291
01/02/10	7157	02/17/10	5348
01/03/10	7319	02/18/10	5951
01/04/10	7563	02/19/10	6134
01/05/10	6798	02/20/10	5757
01/06/10	7080	02/21/10	5976
01/07/10	6166	02/22/10	6397
01/08/10	6879	02/23/10	6624
01/09/10	6022	02/24/10	6256
01/10/10	5833	02/25/10	6258
01/11/10	6185	02/26/10	6201
01/12/10	5782	02/27/10	6118
01/13/10	6094	02/28/10	5989
01/14/10	6052	03/01/10	5103
01/15/10	6492	03/02/10	3650
01/16/10	6190	03/03/10	5128
01/17/10	5326	03/04/10	4718
01/18/10	6015	03/05/10	4932
01/19/10	6426	03/06/10	4254
01/20/10	6187	03/07/10	5809
01/21/10	5627	03/08/10	5798
01/22/10	5629	03/09/10	5203
01/23/10	5095	03/10/10	4662
01/24/10	5393	03/11/10	4475
01/25/10	5087	03/12/10	4467
01/26/10	5251	03/13/10	4562
01/27/10	5324	03/14/10	4479

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitation : 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambient : 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
03/15/10	4861	04/30/10	4579
03/16/10	5068	05/01/10	5685
03/17/10	4945	05/02/10	5516
03/18/10	5016	05/03/10	5469
03/19/10	5305	05/04/10	5941
03/20/10	5060	05/05/10	6290
03/21/10	4823	05/06/10	6267
03/22/10	4704	05/07/10	5913
03/23/10	4394	05/08/10	6540
03/24/10	4795	05/09/10	6241
03/25/10	4293	05/10/10	6262
03/26/10	3505	05/11/10	6577
03/27/10	4381	05/12/10	6530
03/28/10	4236	05/13/10	6517
03/29/10	4173	05/14/10	6143
03/30/10	3966	05/15/10	4036
03/31/10	3336	05/16/10	3092
04/01/10	5789	05/17/10	3191
04/02/10	6048	05/18/10	3576
04/03/10	5991	05/19/10	4170
04/04/10	6131	05/20/10	4382
04/05/10	5839	05/21/10	3791
04/06/10	5373	05/22/10	7427
04/07/10	4571	05/23/10	7924
04/08/10	4603	05/24/10	7013
04/09/10	4440	05/25/10	6708
04/10/10	4742	05/26/10	6514
04/11/10	4608	05/27/10	6313
04/12/10	4342	05/28/10	6399
04/13/10	4905	05/29/10	6751
04/14/10	5848	05/30/10	6949
04/15/10	5536	05/31/10	6921
04/16/10	5770	06/01/10	7213
04/17/10	4951	06/02/10	6927
04/18/10	5841	06/03/10	5770
04/19/10	4541	06/04/10	6984
04/20/10	5135	06/05/10	6367
04/21/10	5446	06/06/10	6869
04/22/10	5142	06/07/10	5964
04/23/10	5493	06/08/10	5881
04/24/10	5280	06/09/10	6773
04/25/10	5791	06/10/10	6608
04/26/10	5655	06/11/10	4638
04/27/10	5874	06/12/10	3229
04/28/10	5334	06/13/10	3255
04/29/10	5617	06/14/10	3352

Table A-6. Specific Conductance Data at SGS D-001

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 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
06/15/10	6172	07/31/10	7171
06/16/10	4514	08/01/10	7259
06/17/10	4638	08/02/10	7121
06/18/10	5176	08/03/10	6564
06/19/10	4059	08/04/10	7054
06/20/10	4716	08/05/10	7279
06/21/10	5245	08/06/10	6914
06/22/10	5114	08/07/10	7670
06/23/10	5869	08/08/10	7477
06/24/10	5342	08/09/10	7658
06/25/10	6734	08/10/10	7515
06/26/10	6277	08/11/10	7648
06/27/10	6145	08/12/10	6750
06/28/10	6327	08/13/10	7725
06/29/10	7099	08/14/10	7528
06/30/10	6197	08/15/10	6416
07/01/10	6452	08/16/10	6071
07/02/10	6725	08/17/10	6524
07/03/10	6912	08/18/10	7487
07/04/10	7203	08/19/10	7392
07/05/10	6222	08/20/10	7151
07/06/10	7346	08/21/10	6909
07/07/10	6751	08/22/10	6645
07/08/10	6586	08/23/10	6776
07/09/10	6559	08/24/10	6556
07/10/10	6714	08/25/10	6824
07/11/10	4568	08/26/10	6802
07/12/10	4542	08/27/10	6650
07/13/10	6931	08/28/10	6625
07/14/10	7516	08/29/10	6192
07/15/10	7310	08/30/10	6105
07/16/10	7172	08/31/10	6427
07/17/10	7132	09/01/10	5462
07/18/10	6895	09/02/10	6256
07/19/10	6676	09/03/10	5638
07/20/10	6508	09/04/10	6755
07/21/10	6902	09/05/10	6768
07/22/10	7064	09/06/10	6463
07/23/10	6476	09/07/10	6670
07/24/10	5971	09/08/10	6664
07/25/10	6132	09/09/10	6170
07/26/10	6679	09/10/10	6182
07/27/10	6274	09/11/10	6801
07/28/10	6178	09/12/10	7027
07/29/10	7014	09/13/10	4705
07/30/10	6345	09/14/10	6925

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
09/15/10	6879	10/31/10	5682
09/16/10	6726	11/01/10	6305
09/17/10	6983	11/02/10	6070
09/18/10	7157	11/03/10	5956
09/19/10	6863	11/04/10	5704
09/20/10	7265	11/05/10	5442
09/21/10	6801	11/06/10	5107
09/22/10	6666	11/07/10	5574
09/23/10	6114	11/08/10	4475
09/24/10	6221	11/09/10	5540
09/25/10	5935	11/10/10	5037
09/26/10	5890	11/11/10	5374
09/27/10	5926	11/12/10	5384
09/28/10	5787	11/13/10	5118
09/29/10	5628	11/14/10	5017
09/30/10	5494	11/15/10	4771
10/01/10	5504	11/16/10	4830
10/02/10	5721	11/17/10	5024
10/03/10	5088	11/18/10	4692
10/04/10	5550	11/19/10	5000
10/05/10	5297	11/20/10	5246
10/06/10	4662	11/21/10	5166
10/07/10	5511	11/22/10	5227
10/08/10	5612	11/23/10	5455
10/09/10	5600	11/24/10	5165
10/10/10	5504	11/25/10	5511
10/11/10	5417	11/26/10	5642
10/12/10	5354	11/27/10	5482
10/13/10	5696	11/28/10	5555
10/14/10	5584	11/29/10	5535
10/15/10	5644	11/30/10	5681
10/16/10	5500	12/01/10	5395
10/17/10	5579	12/02/10	5139
10/18/10	5759	12/03/10	5075
10/19/10	5409	12/04/10	5061
10/20/10	5677	12/05/10	5337
10/21/10	6034	12/06/10	5502
10/22/10	6237	12/07/10	5666
10/23/10	5758	12/08/10	5788
10/24/10	5987	12/09/10	5649
10/25/10	5553	12/10/10	5957
10/26/10	5997	12/11/10	5803
10/27/10	5958	12/12/10	5816
10/28/10	5631	12/13/10	5636
10/29/10	5313	12/14/10	3886
10/30/10	5697	12/15/10	4675

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
D-001 Effluent Limitation : 8,653 $\mu\text{mhos/cm}$
95th percentile of ambient : 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
12/16/10	6006	02/02/11	5996
12/17/10	5855	02/03/11	5952
12/18/10	6346	02/04/11	5992
12/19/10	6075	02/05/11	5934
12/20/10	6032	02/06/11	5863
12/21/10	6075	02/07/11	5666
12/22/10	4955	02/08/11	6162
12/23/10	6071	02/09/11	5924
12/24/10	6188	02/10/11	5925
12/25/10	6110	02/11/11	5781
12/26/10	6289	02/12/11	5862
12/27/10	6019	02/13/11	5986
12/28/10	6387	02/14/11	5135
12/29/10	6137	02/15/11	6139
12/30/10	6532	02/16/11	6313
12/31/10	6436	02/17/11	6392
01/01/11	6227	02/18/11	6288
01/02/11	5925	02/19/11	5919
01/03/11	5363	02/20/11	5857
01/04/11	5467	02/21/11	6010
01/05/11	5801	02/22/11	5887
01/06/11	6155	02/23/11	5585
01/07/11	5701	02/24/11	5863
01/08/11	5821	02/25/11	5656
01/09/11	5791	02/26/11	6127
01/10/11	5882	02/27/11	6157
01/13/11	6777	02/28/11	6073
01/14/11	6658	03/01/11	6013
01/15/11	6525	03/02/11	5325
01/16/11	6450	03/03/11	5728
01/17/11	6373	03/04/11	6348
01/18/11	6462	03/05/11	6272
01/19/11	6359	03/06/11	6192
01/20/11	6355	03/07/11	6186
01/21/11	6089	03/08/11	6008
01/22/11	6192	03/09/11	6471
01/23/11	6119	03/10/11	6408
01/24/11	6105	03/11/11	6134
01/25/11	6167	03/12/11	6099
01/26/11	6295	03/13/11	6012
01/27/11	6094	03/14/11	5946
01/28/11	5996	03/15/11	5575
01/29/11	6155	03/16/11	5817
01/30/11	6238	03/17/11	5889
01/31/11	6113	03/18/11	5682
02/01/11	5557	03/19/11	6097

Table A-6. Specific Conductance Data at SGS D-001

Class III Water Quality : 2,130 $\mu\text{mhos/cm}$
 D-001 Effluent Limitati 8,653 $\mu\text{mhos/cm}$
 95th percentile of ambie 1,420 $\mu\text{mhos/cm}$

Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)	Date	D-001 Specific Conductance ($\mu\text{mhos/cm}$)
03/20/11	4887	05/05/11	7407
03/21/11	6120	05/06/11	6507
03/22/11	6210	05/07/11	7351
03/23/11	6441	05/08/11	6755
03/24/11	5806	05/09/11	7251
03/25/11	6328	05/10/11	7143
03/26/11	6109	05/11/11	7240
03/27/11	6513	05/12/11	6950
03/28/11	5911	05/13/11	5289
03/29/11	5279	05/14/11	7610
03/30/11	5574	05/15/11	7589
03/31/11	5015	05/16/11	7300
04/01/11	5355	05/17/11	5373
04/02/11	5603	05/18/11	7134
04/03/11	6281	05/19/11	7275
04/04/11	6855	05/20/11	7252
04/05/11	6152	05/21/11	7306
04/06/11	6311	05/22/11	6945
04/07/11	6585	05/23/11	6238
04/08/11	6514	05/24/11	7481
04/09/11	6459	05/25/11	7418
04/10/11	6628	05/26/11	7261
04/11/11	5936	05/27/11	5539
04/12/11	6250	05/28/11	4976
04/13/11	6606	05/29/11	5749
04/14/11	6187	05/30/11	6174
04/15/11	6325	05/31/11	6821
04/16/11	6061	06/01/11	7404
04/17/11	6159		
04/18/11	5821		
04/19/11	5412	Average	6,620.8
04/20/11	5762	Maximum	8,538.0
04/21/11	6347	Standard Dev	1,283.5
04/22/11	6167	95 th Percentile	8,193.2
04/23/11	6992		
04/24/11	6528		
04/25/11	6010		
04/26/11	6095		
04/27/11	6242		
04/28/11	6425		
04/29/11	6805		
04/30/11	6766		
05/01/11	6789		
05/02/11	6843		
05/03/11	7295		
05/04/11	7305		

Sources: SECI, 2011.
 ECT, 2011.

APPENDIX B

CORMIX INPUT AND OUTPUT DATA

This data is provided electronically on a CD

Appendix 10.2.3

Hazardous Waste Disposal Applications/Permits

10.2.3 Hazardous Waste Disposal Applications/Permits

The Seminole Combined-Cycle Facility (SCCF) may occasionally generate small quantities of hazardous waste (i.e., less than 1 kilogram of acutely hazardous waste and less than 100 kilograms of hazardous waste per month), which results in a conditionally exempt small-quantity generator status.³ No federal or state application or permit is required for the SCCF.

³ The U.S. Environmental Protection Agency recently promulgated revisions to its hazardous waste regulations that change the designation “conditionally-exempt small quantity generator” to “very small quantity generator.” See 40 CFR 260.10 and 262.14. FDEP is currently undergoing rulemaking to incorporate these and other EPA revisions into Florida’s hazardous waste management rules in Chapter 62-730, F.A.C.

Appendix 10.2.4

Section 10 or 404 Applications/Permits

10.2.4 Section 10 or 404 Applications/Permits

The Seminole Combined-Cycle Facility (SCCF) will not impact any wetlands or water bodies. Appendix 10.4 contains the SCCF Joint Environmental Resource Permit/Section 404 permit application. The application addresses only stormwater management aspects of the SCCF.

Appendix 10.2.5

Prevention of Significant Deterioration Permit Application

10.2.5 Prevention of Significant Deterioration Permit Application

This appendix provides the Florida Department of Environmental Protection (FDEP)-required prevention of significant deterioration (PSD)/air construction permit application for the Seminole Combined-Cycle Facility (SCCF). The permit application has also been submitted separately to FDEP's Division of Air Resources Management.



Seminole Combined-Cycle Facility

Air Construction/Prevention of Significant Deterioration Permit Application

December 2017



Prepared by:

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List of Acronyms and Abbreviations

°	degree
°F	degree Fahrenheit
µg/m ³	microgram per cubic meter
AMS	American Meteorological Society
ARP	Acid Rain Program
BACT	best available control technology
BEEST	Providence Engineering and Environmental Group, LLC, BEEST Suite
Btu/ft ³	British thermal unit per cubic foot
Btu/gal	British thermal unit per gallon
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CCS	carbon capture and sequestration
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CH ₄	methane
CI	compression ignition
CO	carbon monoxide
CO ₂	carbon dioxide
CO ₂ e	carbon dioxide equivalent
CSAPR	Cross-State Air Pollution Rule
CTG	combustion turbine generator
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
F.A.C.	Florida Administrative Code
FBN	fuel-bound nitrogen
FDEP	Florida Department of Environmental Protection
FGD	flue gas desulfurization
FR	Federal Register
ft-agl	foot above ground level
ft-msl	foot above mean sea level
g/bhp-hr	gram per brake horsepower-hour
GCP	good combustion practice
GE	General Electric
GEP	good engineering practice
GHG	greenhouse gas
gr/100 dscf	grain per 100 dry standard cubic feet
gr/100 scf	grain per 100 standard cubic feet

List of Acronyms and Abbreviations

(Continued, Page 2 of 3)

H ₂ SO ₄	sulfuric acid
ha	hectare
HAP	hazardous air pollutant
HHV	higher heating value
hp	horsepower
hr/yr	hour per year
HRSG	heat recovery steam generator
ICE	internal combustion engine
km	kilometer
lb/hr	pound per hour
lb/MMBtu	pound per million British thermal units
lb/MWh	pound per megawatt-hour
LHV	lower heating value
MACT	maximum achievable control technology
MECL	minimum emissions compliance load
MMBtu/hr	million British thermal units per hour
MW	megawatt
NAAQS	national ambient air quality standards
NESHAP	National Emissions Standard for Hazardous Air Pollutants
NMHC	nonmethane hydrocarbon
NNSR	nonattainment new source review
NO	nitric oxide
NO ₂	nitrogen dioxide
NO _x	nitrogen oxides
NSPS	New Source Performance Standard
NSR	new source review
OCEC	Okeechobee Clean Energy Center
PM	particulate matter
PM ₁₀	particulate matter less than or equal to 10 micrometers
PM _{2.5}	particulate matter less than or equal to 2.5micrometers
ppb	part per billion
ppm	part per million
ppmvd	part per million by volume dry
PSD	prevention of significant deterioration
QA	quality assurance
RACT	reasonably achievable control technology
RICE	reciprocating internal combustion engine

List of Acronyms and Abbreviations

(Continued, Page 3 of 3)

SCCF	Seminole Combined Cycle Facility (or Project)
SCR	selective catalytic reduction
SECI	Seminole Electric Cooperative, Inc.
SER	significant emissions rate
SF ₆	sulfur hexafluoride
SGS	Seminole Generating Station
SIC	standard industrial classification
SO ₂	sulfur dioxide
STG	steam turbine generator
tpy	ton per year
TSP	total suspended particulate
ULSD	ultra-low-sulfur diesel
VE	visible emissions
VOC	volatile organic compound

1.0 Introduction and Summary

1.1 Introduction

Seminole Electric Cooperative, Inc. (SECI), currently operates the Seminole Generating Station (SGS) located in Palatka, Putnam County, Florida under Title V Air Operation Permit No. 1070025-027-AV, with an effective date of February 27, 2017, and an expiration date of December 31, 2019. This Title V Air Operation Permit authorizes the operation of Units 1 and 2¹, two coal-fired, dry-bottom, wall-fired boilers each rated at 736 megawatts (MW) (nominal); a coal storage yard, limestone; sludge and ash handling and storage; emergency equipment (diesel-fired electrical generator and fire water pump); and general plant fugitive emissions. The Existing SGS Units are equipped with low-nitrogen oxides (NO_x) burners and a selective catalytic reduction (SCR) system to reduce NO_x emissions, an electrostatic precipitator (ESP) to reduce particulate matter (PM) emissions, and a wet limestone flue gas desulfurization (FGD) system to reduce sulfur dioxide (SO₂) emissions.

SECI plans to construct and operate a 1,183 MW (gross nominal) natural gas-fired, combined-cycle combustion turbine generator (CTG) facility on the existing SGS site, with a winter net nominal capacity of 1,050 MW. Since SCCF will be under common control and ownership, have the same standard industrial classification (SIC) code, and be constructed and operated on the SGS site, construction of SCCF will be considered a major modification to an existing major stationary source.

As part of this modification, coincident with the declared commercial operation of SCCF, SECI intends to permanently remove from service one of the two Existing SGS Units.² The addition of SCCF and the permanent removal from service of either one of the two Existing SGS Units will result in a net emissions decrease in all regulated pollutants with the exception of volatile organic

¹ Also referred to herein and throughout this document as the Existing SGS Units and/or SGS Units 1 and 2.

² Remaining SGS Unit as used throughout this document is intended to refer to the Existing SGS Unit that will continue to be operated beyond achieving commercial operation of the proposed SCCF. A decision as to which of the two Existing SGS Units will be removed from service will be made in the future.

compounds (VOCs). The net emissions increase of VOCs will be greater than the applicability threshold for prevention of significant deterioration (PSD) and will subject VOC emissions to PSD review. Section 3.0 provides a more detailed discussion of the PSD applicability analysis and the specific PSD requirements.

SCCF will consist of one power block with two CTGs, two heat recovery steam generators (HRSGs) equipped with duct burners, and one steam turbine generator (STG) arranged in a two-on-one configuration. The CTGs will be General Electric (GE) Model 7HA.02, one of the most efficient CTGs currently on the market. SCCF will also have ancillary equipment, including two fuel gas dew point heaters rated at 9.99 million British thermal units per hour (MMBtu/hr) or less, one diesel-fired emergency fire water pump engine rated at 250 horsepower (hp), and one 16-cell mechanical draft cooling tower for process cooling water. The CTG/HRSGs and fuel gas dew point heaters will be fired exclusively with pipeline-quality natural gas, and the emergency fire water pump engine will be fired exclusively with ultra-low-sulfur diesel (ULSD) fuel.

Each CTG/HRSG unit will be permitted to operate up to 8,760 hours per year (hr/yr), including up to 8,760 hr/yr of natural gas-fired HRSG duct burner operation. The fuel gas dew point heaters and cooling tower will also be permitted to operate up to 8,760 hr/yr. The emergency fire water pump will be limited to 100 hr/yr of operation for maintenance and testing purposes. Potential emissions from the emergency fire water pump will be based on operating 500 hr/yr in accordance with U.S. Environmental Protection Agency (EPA) guidance. There are no hourly limits on the emergency engine when operating for emergency purposes.

This report is organized as follows:

- Section 1.2 provides an overview and summary of the key regulatory determinations and conclusions.
- Section 2.0 describes the proposed facility and associated air emissions.
- Section 3.0 describes new source review (NSR) requirements and discusses applicability of these requirements to the proposed SCCF.
- Section 4.0 describes applicable state and federal emissions standards.

- Section 5.0 describes the control technology review, including a best available control technology (BACT) analysis for those pollutants subject to PSD review.
- Section 6.0 describes the additional impact analysis.

Appendices A through C provide the Florida Department of Environmental Protection (FDEP) Application for Air Permit—Long Form, SCCF potential emissions rate calculations, and the SCCF netting analysis calculations, respectively. Appendix D contains the Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emissions Rate (LAER) Clearinghouse (RBLC) tables for VOC emissions only. Appendix E contains Precautions to Prevent Emissions of Unconfined Particulate Matter. Appendix F contains the Acid Rain Part Application form.

1.2 Summary

The primary source of emissions from SCCF will result from the combustion of natural gas in the two CTG/HRSG units. Principal air contaminants that will be emitted from the CTG/HRSG units include NO_x, SO₂, carbon monoxide (CO), VOCs, PM/particulate matter less than or equal to 10 micrometers (PM₁₀)/particulate matter less than or equal to 2.5 micrometers (PM_{2.5}), carbon dioxide (CO₂), and sulfuric acid (H₂SO₄) mist. The CTG/HRSG units will also emit trace amounts of metallic and organic compounds. Ancillary SCCF emissions sources include a 16-cell mechanical draft cooling tower, natural gas-fired fuel gas dew point heaters, and a diesel fuel-fired emergency fire water pump diesel engine.

Construction of SCCF is scheduled to start between mid-2019 and early 2020 with commercial operation planned for late 2022.

Based on an evaluation of anticipated worst-case annual operating scenarios, SCCF will have a net emissions increase of VOC emissions greater than the PSD significant emissions rate (SER) and thus subject VOC to PSD review, including conducting a BACT analysis. SCCF will have a net emissions decrease for the other regulated pollutants. Therefore, only VOC emissions will be subject to PSD applicability and review.

The regulatory applicability and control technology analyses required for this permit application have resulted in the following conclusions that address primary SCCF emissions sources:

- Dry low-NO_x combustion and SCR will be used to control NO_x emissions from the CTG/HRSGs to 7 parts per million by volume dry (ppmvd) corrected to 15-percent oxygen on a 24-hour block average. The proposed secondary NO_x emissions limit for all operating scenarios greater than 75-percent load, including periods of startup, shutdown, dry low-NO_x tuning, and documented malfunction is 15 ppmvd corrected to 15-percent oxygen on a 30-operating-day rolling average. The proposed secondary NO_x emissions limit for all operating scenarios less than 75-percent load is 96 ppmvd corrected to 15-percent oxygen on a 30-operating-day rolling average. This proposed secondary NO_x emissions limit represents the New Source Performance Standard (NSPS) Subpart KKKK limit for a stationary CTG firing natural gas. The emergency fire water pump diesel engine will achieve a NO_x plus nonmethane hydrocarbon (NMHC) emissions rate of 3.0 grams per brake horsepower-hour (g/bhp-hr), which complies with NSPS Subpart IIII.
- Good combustion practices (GCP) and an oxidation catalyst will be used to control CO emissions. The proposed CO emissions limit is 10 ppmvd corrected to 15-percent oxygen with and without duct firing. This CO emission limit represents the CO emissions from the combustion turbine with and without duct firing. The emergency fire water pump diesel engines will achieve a CO emissions rate of 2.6 g/hp hr, which complies with NSPS Subpart IIII.
- GCP and an oxidation catalyst will be used to control VOC emissions. The proposed VOC BACT emissions limits are 1.0 ppmvd corrected to 15-percent oxygen without duct firing and 2.0 ppmvd corrected to 15-percent oxygen with duct firing. The emergency fire water pump diesel engines will achieve a NO_x + NMHC emissions rate of 3.0 g/bhp hr, which complies with NSPS Subpart IIII.
- Exclusive use of pipeline-quality natural gas and GCP will be used to control PM/PM₁₀/PM_{2.5} emissions. Pipeline-quality natural gas will contain a maximum annual average sulfur content of 2.0 grains per 100 standard cubic feet (gr/100 scf). The emergency fire water pump diesel engine will be fired exclusively with ULSD fuel oil and will achieve a PM/PM₁₀/PM_{2.5} emissions rate of 0.15 g/bhp-hr, which complies with NSPS Subpart IIII. The mechanical draft cooling towers will employ

high-efficiency drift eliminators to achieve a drift loss rate of no more than 0.0005 percent of the cooling tower recirculating water flow.

- Exclusive use of pipeline-quality natural gas will be used to control SO₂ and H₂SO₄ mist. The proposed SO₂/H₂SO₄ limit is the exclusive use of pipeline-quality natural gas with a maximum annual average sulfur content of 2.0 gr/100 scf. The emergency fire water pump diesel engine will be fired exclusively with ULSD fuel oil, containing a maximum sulfur content of 0.0015 percent by weight.
- Exclusive use of pipeline-quality natural gas and high efficiency combustion turbine design utilizing state-of-the-art combustion technology will be used to control GHG emissions.

2.0 Project Description

2.1 Project Location, Area Map, and Plot Plan

The proposed SCCF will be located within an approximately 32-acre portion of the existing SGS site. The facility will consist of a natural gas-fired combined-cycle combustion turbine unit arranged in a two-on-one configuration, utilizing two advanced CTGs, two HRSGs, one STG, and the directly associated facilities.

Figure 2-1 provides a site location map for the existing SGS. Figure 2-2 provides the location of the proposed SCCF in relation to the overall SGS site. Figure 2-3 provides a detailed map showing SCCF emissions units and ancillary equipment locations.

Major components of the facility will consist of:

- Two CTG/HRSG units equipped with evaporative coolers, duct burners, and an associated STG.
- Two 9.99-MMBtu/hr or less natural gas-fired fuel gas dew point heaters.
- One 250-hp diesel fuel-fired emergency fire water pump.
- One 16-cell wet mechanical draft cooling tower.
- Ancillary equipment, including raw and demineralized water storage tanks and aqueous ammonia storage and handling equipment.
- Natural gas piping components.
- Circuit breakers.

The two CTGs will be GE 7HA.02 units utilizing state-of-the-art combustion technology. Each CTG will be equipped with evaporative cooling designed to increase the turbine intake air density during periods of higher ambient air temperatures. The CTGs will be capable of operating between a nominal minimum emissions compliance load (MECL) and 100-percent load. MECL is defined as the minimum steady-state load at which the combustion turbine can

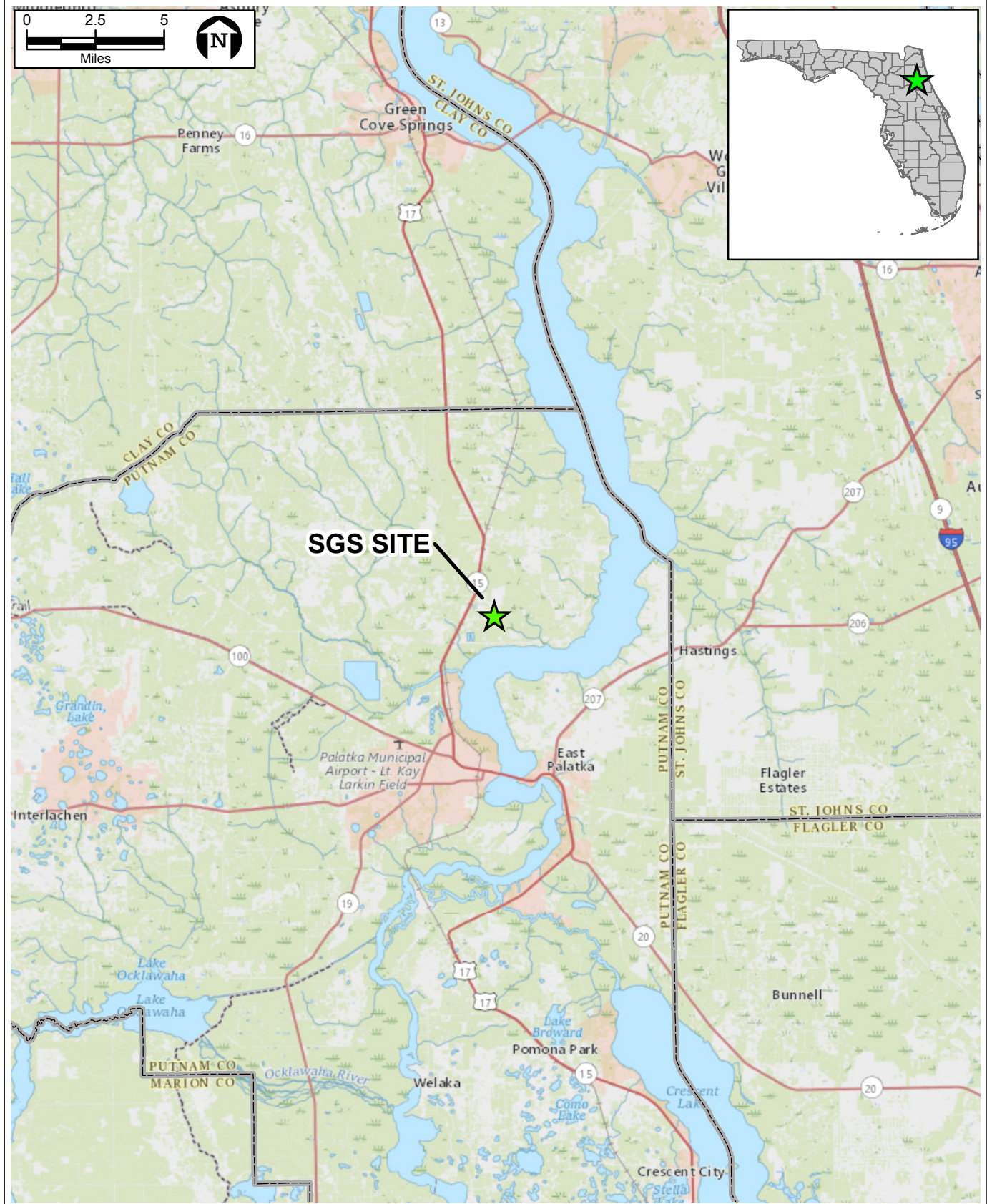


FIGURE 2-1.
REGIONAL LOCATION OF SGS SITE

Sources: USGS, 2017; ECT, 2017.



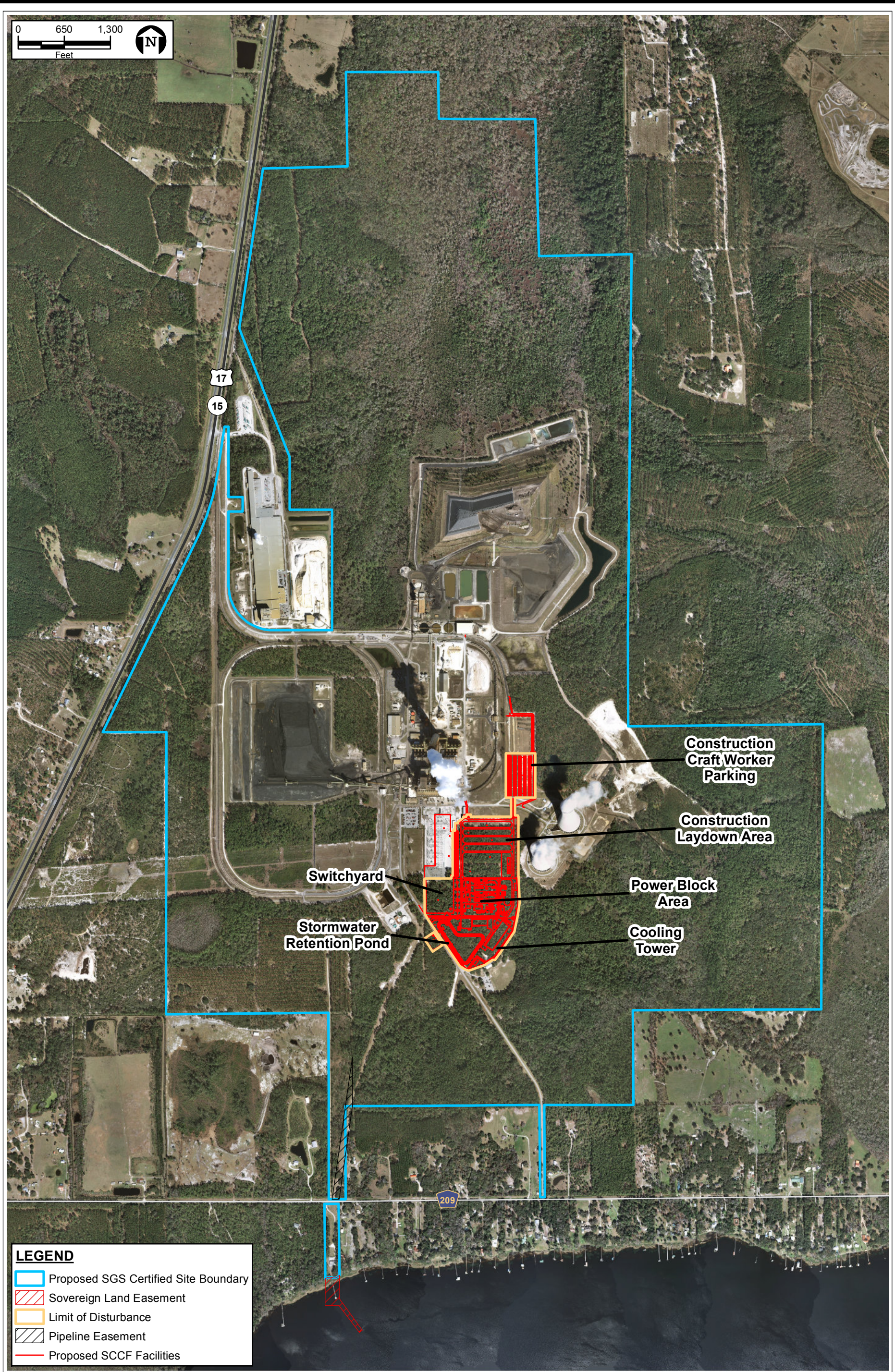


FIGURE 2-2.
SCCF PROJECT SITE LAYOUT MAP

Sources: FDOT, 2014, 2016; Putnam Co PA, 2016; ECT, 2017.

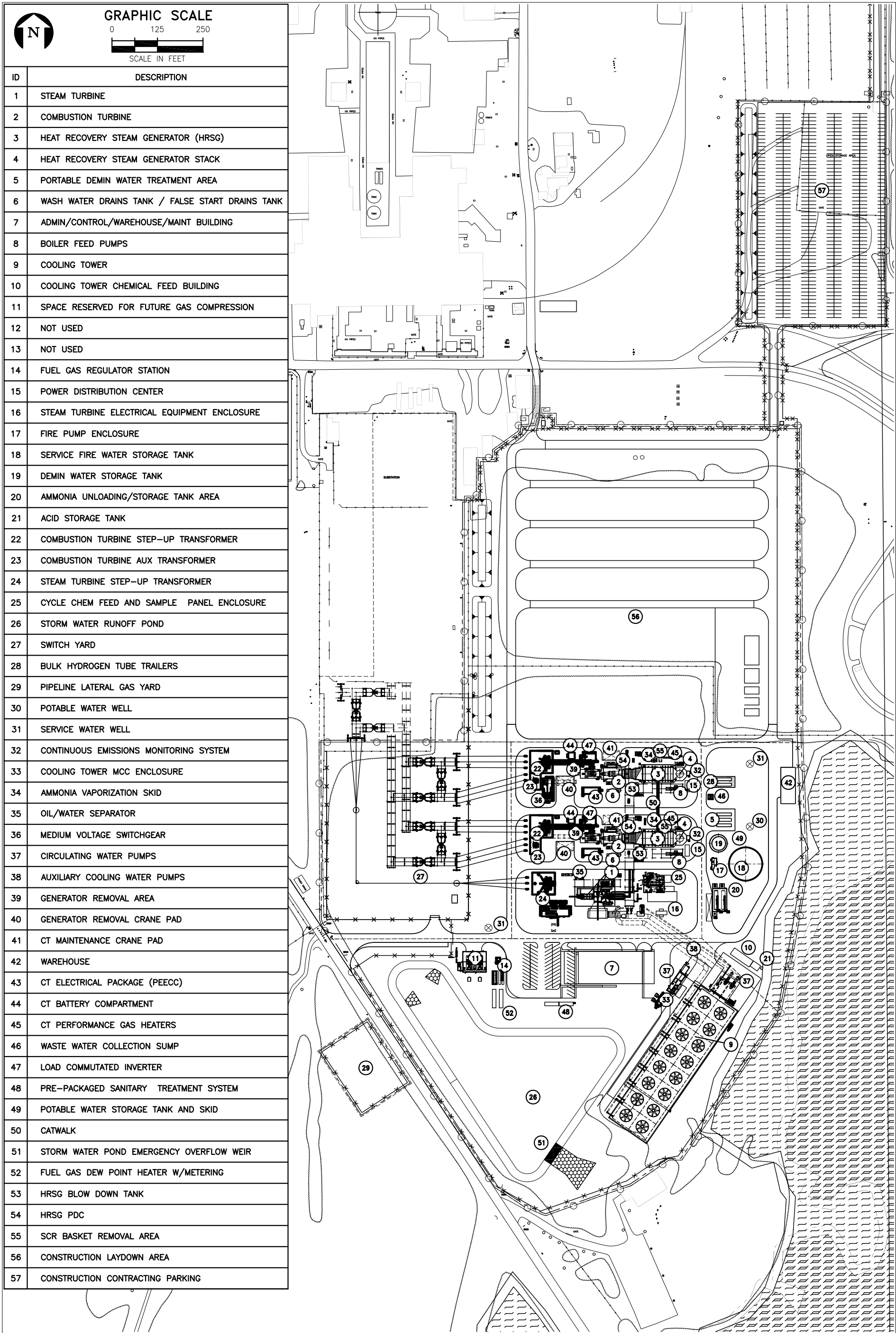


FIGURE 2-3.

SCCF PROJECT SITE DETAILED EMISSIONS UNITS MAP

Sources: B&V, 2017; ECT, 2017.



operate at any given ambient condition and maintain compliance with all emission limits. The associated HRSG units will each have the capability of supplementary duct burner firing. Each supplemental duct burner will have a nominal heat input of 250 MMBtu/hr. The HRSG units will furnish steam to the STG, which will produce additional electricity. The two CTGs and one STG will have a gross nominal generating capacity of approximately 1,183 MW of electricity.

SECI proposes to permit the CTG/HRSG to operate for 8,760 hr/yr, including up to 8,760 hr/yr for duct burner firing per CTG/HRSG. The fuel gas dew point heaters and wet mechanical draft cooling tower will be permitted to operate up to 8,760 hr/yr. The emergency diesel-fired fire water pump will be permitted to operate up to 100 hr/yr for maintenance and testing purposes only. The hours of operation for the emergency fire water pump are not limited when operating due to an emergency.

2.2 Project Description and Process Flow Diagram

Figure 2-4 presents a process flow diagram for SCCF CTG/HRSGs and STG arranged in a two-on-one configuration. The CTG will be the GE 7HA.02 utilizing state-of-the-art combined-cycle combustion technology. SCCF will have a gross nominal generating capacity of 1,183 MW, with a net nominal generating capacity of approximately 1,050 MW.

CTGs are heat engines that convert latent fuel energy into work using compressed hot gas as the working medium. CTGs deliver mechanical output by means of a rotating shaft used to drive an electrical generator thereby converting a portion of the engine's mechanical output to electrical energy. Ambient air is first filtered and then compressed by the CTG compressor. The CTG compressor increases the pressure of the combustion air stream and also raises its temperature. On hot days, the turbine inlet ambient air can be cooled by evaporative cooling. Evaporative cooling is the thermodynamic process of lowering the combustion turbine intake ambient air temperature by introducing water droplets or mist. Heat is removed from the intake air by evaporation of the water droplets or mist, thus lowering the intake air temperature. Lower intake air temperature

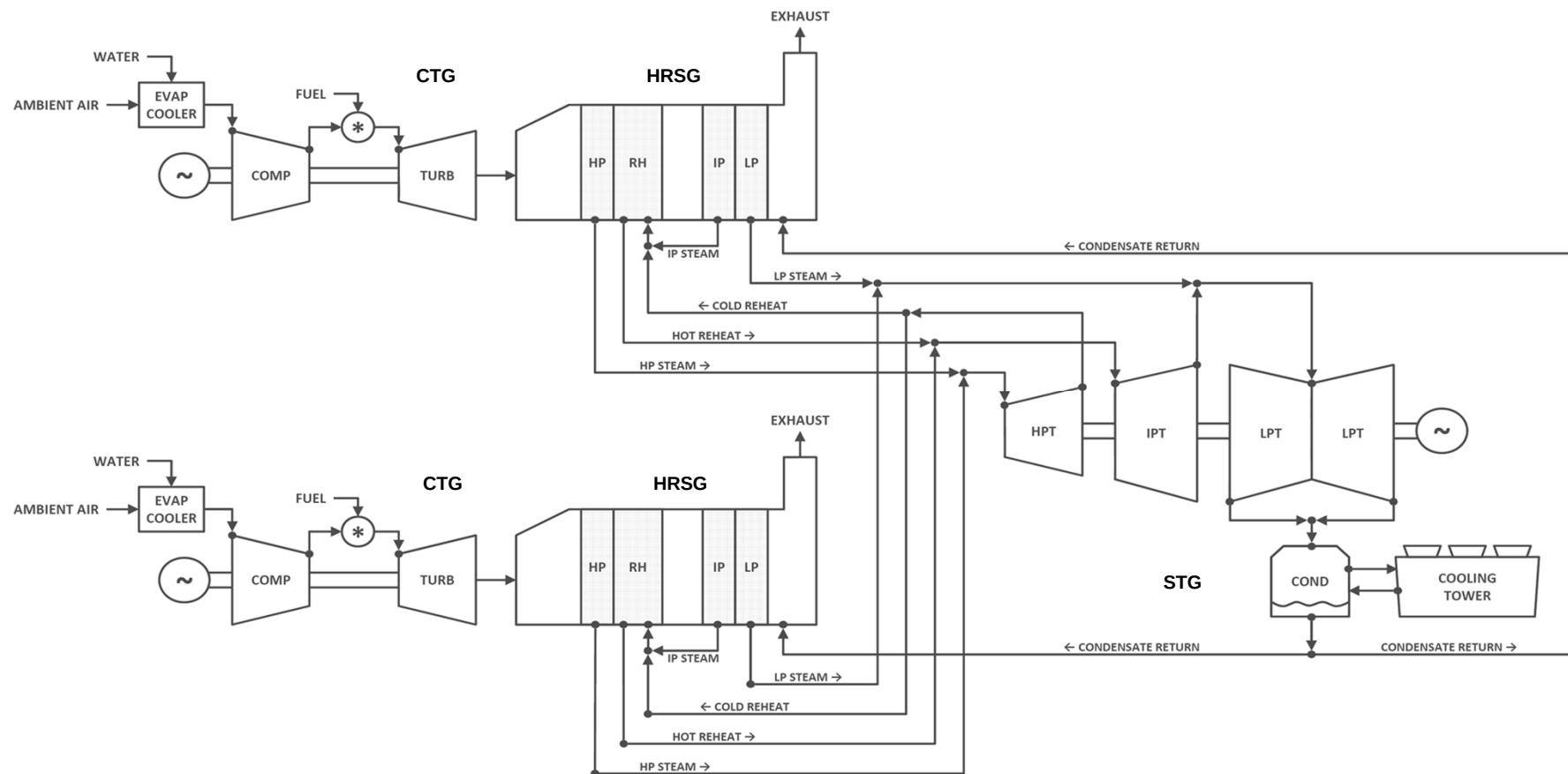


FIGURE 2-4.
PROCESS FLOW DIAGRAM

Sources: B&V, 2016.

results in an increase in the intake air density and increased power output. The compressed combustion air is then combined with natural gas fuel and burned in the CTG's high-pressure combustor to produce hot exhaust gases. Next, these high-pressure, hot gases expand and turn the CTG to produce rotary shaft power used to drive an electric generator as well as the CTG combustion air compressor.

The hot exhaust gases from the CTGs will then flow to the HRSGs for the production of low-, intermediate-, and high-pressure steam. Each HRSG recovers exhaust heat from the CTG to produce steam to power the STG. The STG, in turn, will drive an electric generator. Each of the HRSGs will be equipped with duct burners to provide additional steam as required to meet power demands. The duct burners will be located in the HRSGs and fired exclusively with pipeline-quality natural gas. Following recovery of the CTG exhaust waste heat by the HRSGs, the exhaust gases are discharged to the atmosphere at a much lower temperature through an exhaust stack.

Normal operation is expected to consist of both CTG/HRSG units operating at base load with supplemental duct burner firing. Alternate facility operating modes include evaporative cooling of the combustion intake air and reduced load operation (i.e., between MECL and 100 percent of base load) for either of the two CTG/HRSG units, depending on power demands. The facility will not include bypass stacks and will generally operate in combined-cycle mode. However, the STG can be bypassed if and when necessary, and hence the facility will be capable of operating absent the STG.

The CTGs and duct burners will use dry low-NO_x combustion technology and SCR systems to control NO_x air emissions. Good combustion practices and an oxidation catalyst will be employed to control CO and VOC emissions. The exclusive use of pipeline-quality natural gas in the CTGs and HRSG duct burners will minimize PM/PM₁₀/PM_{2.5}, SO₂, and H₂SO₄ air emissions from the CTG/HRSG units.

2.3 Emissions

Table 2-1 provides maximum hourly pollutant emissions rates for each CTG/HRSG unit based on three different loads and three different ambient temperatures, including evaporative cooling and duct burner operation. Appendix B, Table B-1, defines the 14 operating cases, and Table B-2

provides hourly pollutant emissions rates for all 14 cases. The highest hourly emissions rate for each pollutant is identified, taking into account load, ambient temperature, and duct firing. Maximum hourly emissions rates for all pollutants, in units of pounds per hour (lb/hr), are projected to occur for operations at low ambient temperature, CTG base load, and HRSG duct burner firing. The emissions are based on a natural gas sulfur content of 2.0 gr/100 scf. Appendix B provides the basis for these emissions rates.

Table 2-1. CTG/HRSG—Maximum Pollutant Emissions Rates (per CTG/HRSG)

Pollutant	Unit	Value*
NO _x	ppmvd at 15 percent oxygen	7.0
	lb/hr	96.3
SO ₂	ppmvd at 15 percent oxygen	1.32
	lb/hr	25.3
CO	ppmvd at 15 percent oxygen	10
	lb/hr	84.0
VOC	ppmvd at 15 percent oxygen	2.0
	lb/hr	9.6
PM ₁₀ /PM _{2.5} (total)	lb/hr	26.8
H ₂ SO ₄ mist	lb/hr	16.3

*Maximum rates for all operating cases.

Sources: GE, 2017.
ECT, 2017.

Table 2-2 summarizes SCCF potential annual emissions based on the worst-case operating scenario. Potential annual emissions were calculated based on the worst case (i.e., the highest annual emissions per pollutant) of the following three annual operating profiles:

- Annual Operating Profile 1:
 - o 8,760 hr/yr per turbine at 59 degrees Fahrenheit (°F), including:
 - o 8,760 hr/yr per turbine at 59°F (duct burner firing)
- Annual Operating Profile 2:
 - o 8,760 hr/yr per turbine, including:
 - o 8,760 hr/yr per turbine duct burner firing:

Table 2-2. SCCF Potential Annual Emissions Rate Summary

Pollutant	Emissions (tpy)						
	CTG/ HRSG	Cooling Tower	Emergency Fire Water Pump Engine	Fuel Gas Heaters	Natural Gas Piping Components	Circuit Breakers	Total Emissions
Criteria pollutants							
NO _x	840.1	Not applicable	0.3	8.4			848.8
CO	772.0	Not applicable	0.4	7.1			779.4
VOC	89.7	Not applicable	0.1	0.5			90.3
SO ₂	220.8	Not applicable	0.0	0.5			221.3
PM	230.6	1.7	0.02	0.6			232.9
PM ₁₀ (total)	230.6	0.2	0.02	0.6			231.5
PM _{2.5} (total)	230.6	0.2	0.02	0.6			231.5
Lead	0.017	Not applicable	Negligible	Negligible			0.017
Mercury	Negligible	Negligible	Negligible	Negligible			Negligible
HAPs							
Formaldehyde*	9.4	Not applicable	Negligible	Negligible			9.4
Total HAPs	19.2	Not applicable	Negligible	0.2			19.3
Other pollutants							
H ₂ SO ₄ mist	141.9	Not applicable	Negligible	Negligible			141.9
GHG (as CO ₂ e)	3,858,516	Not applicable	82	10,249	24	120	3,868,991

Note: CO₂e = carbon dioxide equivalent.
 GHG = greenhouse gas.
 HAP = hazardous air pollutant.
 tpy = ton per year.

*Highest individual HAP.

Sources: Black & Veatch, 2017.
 ECT, 2017.

- 2,000 hr/yr per turbine at 25°F
- 4,760 hr/yr per turbine at 59°F
- 2,000 hr/yr per turbine at 95°F
- Annual Operating Profile 3:
 - o 8,760 hr/yr per turbine including:
 - o 8,393 hr/yr per turbine DB-firing:
 - 2,000 hr/yr per turbine at 25°F
 - 4,393 hr/yr per turbine at 59°F
 - 2,000 hr/yr per turbine at 95°F
 - o 10 cold-start events
 - o 50 warm-start events
 - o 200 hot-start events
 - o 260 shutdown events

Tables B-3 through B-5 in Appendix B provide the emissions calculations for annual operating Profiles 1, 2, and 3, respectively.

Maximum potential emissions of hazardous air pollutants (HAPs) were also calculated and are presented in Table B-9. Maximum annual potential HAP emissions are based on the heat input (MMBtu/hr) at the average annual ambient temperature of 59°F to the combustion turbines and duct burners assuming both are operating 8,760 hr/yr (Annual Operating Profile 1). HAP emissions were calculated for the combustion turbines and duct burners using emission factors obtained from AP-42, Section 3.1, dated April 2000 for the combustion turbines, and emission factors obtained from AP-42, Section 1.4, dated July 1998, for the duct burners. The SGS facility will remain a major source of HAPs.

GHG potential emissions (expressed as CO₂e) were calculated based on the maximum heat input (MMBtu/hr) to the combustion turbines and duct burners from all three annual operating profiles described above as well as the fuel gas heaters and the emergency fire water pump. Maximum annual potential CO₂e emissions are based on the heat input (MMBtu/hr) at the average annual ambient temperature of 59°F to the combustion turbines and duct burners assuming both are operating 8,760 hr/yr (Annual Operating Profile 1). GHG emissions from the combustion turbines

and duct burners were calculated using emission factors obtained from 40 CFR 98, Mandatory Greenhouse Gas Reporting rule, Table C-1, Default CO₂ Emission Factors and High Heat Values for Various Types of Fuels, and Table C-2, Default methane (CH₄) and N₂O Emission Factors for Various Types of Fuel.

GHG emissions included equipment leaks from natural gas piping components by using emissions factors from 40 CFR 98, Mandatory Greenhouse Gas Reporting rule, Table W-1A, Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production Facilities and Onshore Petroleum and Natural Gas Gathering and Boosting Facilities.

GHG emissions also included potential leaks of sulfur hexafluoride (SF₆) from new circuit breakers. SF₆ is used as electrical insulating gas in circuit breakers. An industry standard emissions loss rate of 0.5 percent was used to estimate SF₆ emissions. A global warming potential of 22,800 was used to calculate carbon dioxide equivalent emissions. Detailed GHG calculations are provided in Appendix B, Table B-8.

2.4 Project Fuels

Key factors in SECI's decision to select a natural gas-fired, combined-cycle CTG facility to meet its future power needs were the exclusive use of clean fuels, fuel costs, and use of proven technology. Use of natural gas will enable SECI to take full advantage of competitive fuel pricing and availability opportunities and transportation options in the future marketplace to provide low-cost, reliable electricity to its customers. ULSD fuel oil will also be fired in the new emergency fire water pump diesel engine.

SCCF will fire natural gas exclusively in the CTGs and HRSG duct burners as well as the fuel gas dew point heaters. Table 2-3 presents the typical composition of pipeline-quality natural gas in Florida.

SCCF will fire ULSD fuel oil exclusively in the new emergency fire water pump engine. Table 2-4 presents the typical composition of ULSD fuel oil, which will have a maximum sulfur content of 0.0015 weight percent.

Table 2-3. Typical Natural Gas Composition

Component	Mole Percent (by volume)
Gas Composition	
I-Pentane	<0.012
N-Pentane	0.007
Propane	0.189
I-butane	0.03
N-butane	0.032
Nitrogen	0.41
Methane	95.045
CO ₂	1.09
Ethane	3.173
Other Characteristics	
Heat content (HHV)	1,027 Btu/ft ³
Sulfur content	2.0 gr/100 dscf (maximum annual average)

Note: Btu/ft³ = British thermal unit per cubic foot.
gr/100 dscf = grain per 100 dry standard cubic feet.

Source: ECT, 2017.

Table 2-4. Typical ULSD Fuel Oil Composition

Component	Maximum
Carbon residue on 10-percent bottoms	0.25 weight percent
Water and sediment	0.50 percent volume
Vanadium	1.5 ppm
Calcium	4.0 ppm
Sulfur	0.0015 weight percent
Ash	100 ppm
Lead	1.0 ppm
Heat content (HHV) (minimum)	130,000 Btu/gal

Note: Btu/gal = British thermal unit per gallon.
ppm = part per million.

Source: ECT, 2017.

3.0 New Source Review Analysis

3.1 National and State Ambient Air Quality Standards

Pursuant to the Clean Air Act (CAA), EPA enacted primary and secondary national ambient air quality standards (NAAQS) for six air pollutants (Title 40, Part 50, Code of Federal Regulations [CFR]). These six air pollutants, or criteria pollutants, are CO, SO₂, nitrogen dioxide (NO₂), ozone, PM, and lead. Primary NAAQS are intended to protect the public health, and secondary NAAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Florida has adopted the federal NAAQS by reference in Rule 62-204.800(1), Florida Administrative Code (F.A.C.). Table 3-1 presents the current NAAQS.

Areas of the country in violation of NAAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements. The proposed SCCF is located in Putnam County approximately 10 kilometers (km) north of the city of Palatka. Putnam County is presently designated either unclassifiable/attainment or not designated with respect to all applicable NAAQS, i.e., NO₂, SO₂, CO, PM₁₀, PM_{2.5}, VOC/ozone and lead.

3.2 Nonattainment New Source Review Applicability

The SCCF site is located in Putnam County and as noted previously, Putnam County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, SCCF is not subject to the nonattainment new source review (NNSR) requirements of Rule 62-212.500, F.A.C.

Table 3-1. National Ambient Air Quality Standards

Pollutant (units)	Averaging Periods	National Standards	
		Primary	Secondary
SO ₂ (ppb)	1-hour*	75	
	3-hour†		500
PM ₁₀ (µg/m ³)	24-hour§	150	150
PM _{2.5} (µg/m ³)	24-hour☼	35	35
	Annual**	12	15
CO (ppm)	1-hour†	35	
	8-hour†	9	
Ozone (ppm)	2008 8-hour†	0.075	0.075
	2015 8-hour†	0.070	0.070
NO ₂ (ppb)	Annual‡	53	53
	1-hour‡‡	100	
Lead (µg/m ³)	Rolling three-month average	0.15	0.15

Note: µg/m³ = microgram per cubic meter.

ppb = part per billion.

ppm = part per million.

The 1971 annual and 24-hour SO₂ standards were revoked on June 2, 2010. However, these standards remain in effect until one year after an area is designated for the 2010 standard.

*Compliance shown with three-year average of the 99th percentile of the annual distribution of the daily maximum 1-hour average concentrations.

†Not to be exceeded more than once per calendar year. Federal standard has been revoked (Volume 75, Page 35580, Federal Register [FR]) for 24-hour SO₂.

‡Arithmetic mean. Federal standard has been revoked (75 FR 35580) for SO₂.

§Standards are attained when expected number of days per calendar year with a 24-hour average concentration above 150 µg/m³, as determined in accordance with 40 CFR 50, Appendix K, is equal to or less than 1.

☼98th percentile concentration, as determined in accordance with 40 CFR 50, Appendix N.

**Arithmetic mean concentration, as determined in accordance with 40 CFR 50, Appendix N.

††Standard attained when the average of the annual fourth-highest daily maximum 8-hour average concentrations over a three-year period are less than or equal to the standard, as determined by 40 CFR 50, Appendix P.

‡‡Compliance shown with three-year average of the 98th percentile of the annual distribution of the daily maximum 1-hour average concentrations.

Sources: 40 CFR 50.

R. 62-204.800(1), F.A.C.

SCCF will be subject to the preconstruction review requirements for PSD applicability Rule 62-212.400, F.A.C. The following sections describe the PSD applicability review for SCCF.

3.3 PSD NSR Applicability

SCCF will have potential net emissions increases greater than one of the PSD SERs listed in Rule 62-210.200, F.A.C. Accordingly, the SCCF will be considered a major modification to an existing major stationary source and is subject to the PSD NSR requirements of Rule 62-210.200, F.A.C. for those pollutants that have an emissions increase of a PSD pollutant and a net emissions increase of a PSD pollutant greater than the specified PSD SER levels. The following subsections describe the detailed PSD applicability analysis performed to determine whether each regulated pollutant is subject to PSD applicability and review.

The methodology for conducting a PSD netting analysis consists of a two-step process. Step 1 consists of calculating the potential emissions increase of the SCCF only for comparison to the PSD SERs. Step 2 consists of calculating the net emissions increase accounting for the baseline actual emissions from any emissions units proposed to be removed from service coincident with commercial operation of SCCF, as well as any contemporaneous creditable increases or decreases as defined in Rule 62-210.200(187), F.A.C.

3.3.1 Step 1—PSD NSR Applicability

In Step 1 of a PSD NSR applicability analysis at an existing PSD facility, the potential annual emissions from the Project alone must be compared to the PSD SERs.

Potential annual emissions for the proposed SCCF were calculated based on maximum hourly emissions rates and potential annual hours of operation for each emissions source. Details on the maximum hourly emissions rates for the CTG/HRSG are presented in Table B-2 in Appendix B and include hourly emissions for three different ambient air temperatures and three different loads. Table B-2 also contains emissions from duct firing at three different ambient air temperatures and evaporative cooling at the mid- and high ambient air temperature cases. The emissions rates presented in Table B-2 are based on a natural gas sulfur content of 2.0 gr/100 scf.

Table 3-2 presents potential annual hours of operation for the proposed emissions units.

Table 3-2. Potential Annual Hours of Operation

Emissions Unit	Potential Annual Hours of Operation (hr/yr)
CTGs*	8,760 per turbine
HRSG duct burner*	8,760 per turbine
Fuel gas dew point heaters	8,760
Cooling tower	8,760
Emergency diesel fire water pump	500

*Annual Profile 3 also includes startups and shutdowns.

Source: ECT, 2017.

Potential annual air emissions for the CTG/HRSGs were calculated based on three different annual operating profiles. Annual operating Profile 1 considered all 8,760 hr/yr of operation to be at the mid-ambient air temperature of 59°F with 8,760 hr/yr of duct burner firing. Table B-3 provides these potential annual emissions.

Annual operating Profile 2 considered 2,000 hr/yr at the low ambient air temperature of 25°F and 2,000 hr/yr at the high ambient air temperature of 95°F. The remaining hours of operation were assumed to be at the mid-ambient air temperature of 59°F. Table B-4 provides the potential annual emissions for operating Profile 2.

Annual operating Profile 3 uses the same methodology as Profile 2 but includes emissions during periods of startup and shutdown and a commensurate reduction in hours of operation at normal load. Per the manufacturer and OEM estimates, a startup is defined as the operation period beginning when continuous fuel flow to the gas turbine is initiated and ending when stack emissions compliance is achieved. A cold startup is defined as a startup in which the turbine has not been operational for the preceding 72 hours or more. A hot startup is defined as a startup in which the turbine has not been operational for 8 hours or less. A warm startup is defined as any startup that is neither a cold nor a hot startup. A shutdown is defined as the operation period

beginning when the turbine load is reduced and stack emissions compliance is not achieved and ending when fuel flow is discontinued to the gas turbine.

SCCF has assumed 10 cold startups, 50 warm startups, 200 hot startups, and 260 shutdowns per year. Emissions during periods of cold, warm, and hot startups and shutdowns have been provided by the turbine manufacturer (GE). These emissions are provided in units of pounds per event. The durations, in minutes, for each startup and shutdown mode are also provided by the turbine manufacturer. Table B-5 provides the potential annual emissions for operating Profile 3.

Table B-8 presents potential greenhouse gas (GHG) emissions, expressed as carbon dioxide equivalent (CO_{2e}), for the entire SCCF. These potential GHG emissions were calculated based on the heat input (MMBtu/hr) to the CTG at base load obtained from manufacturer's data and emissions factors for natural gas combustion from the Mandatory Greenhouse Gas Reporting Rule contained in 40 CFR 68. GHG emissions were also calculated for the emergency fire water pump, fuel gas heaters, natural gas piping components, and circuit breakers. The potential GHG emissions for SCCF is calculated to be 3,868,991 tons per year (tpy).

Tables B-11 thru B-14 provide potential annual emissions for the ancillary equipment, such as the cooling tower, emergency diesel fire water pump, and fuel gas dew point heaters.

Table 3-3 provides comparisons of potential annual emissions rates for SCCF and the PSD SER thresholds. As shown in this table, potential emissions of NO_x, CO, SO₂, PM/PM₁₀/PM_{2.5}, VOC, GHG, and H₂SO₄ mist are each projected to exceed the applicable PSD SER level. Since at least one of these pollutants exceeded the PSD SER, Step 2 of the PSD NSR applicability analysis must be performed. Appendix B provides detailed SCCF emissions rate calculations.

Table 3-3. SCCF Potential Annual Emissions Compared to PSD SERs

Pollutant	SCCF Potential Annual Emissions (tpy)	PSD SER (tpy)	PSD Applicability
CO	779	100	Yes
NO _x	849	40	Yes
SO ₂	221	40	Yes
PM (filterable and condensable)	233	25	Yes
PM ₁₀ (filterable and condensable)	232	15	Yes
PM _{2.5} (filterable and condensable)	232	10	Yes
Ozone/VOC	90	40	Yes
Lead	Negligible	0.6	No
GHG (as CO ₂ e)	3,868,991	75,000	Yes
Fluorides	Not present	3	No
H ₂ SO ₄ mist	142	7	Yes
Hydrogen sulfide	Not present	10	No
Total reduced sulfur (including hydrogen sulfide)	Not present	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Not present	10	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not present	3.5 × 10 ⁻⁶	No
Municipal waste combustor metals (measured as PM)	Not present	15	No
Municipal waste combustor acid gases (measured as SO ₂ and hydrogen chloride)	Not present	40	No
Municipal solid waste landfills emissions (measured as nonmethane organic compounds)	Not present	50	No
Mercury	Negligible	0.1	No
For the pollutants listed above, and for major stationary sources locating within 10 km of a Class I area having an impact equal to or greater than 1 µg/m ³ , 24-hour average	Not applicable	Any amount	No

Sources: Rule 62-210.200(256), F.A.C.
Black & Veatch, 2017.
ECT, 2017.

3.3.2 Step 2—PSD NSR Applicability

In Step 2 of a PSD applicability analysis, contemporaneous emissions increases or decreases must be considered to calculate the net emissions increase for each pollutant and to compare with the PSD SER.

Net emissions increase is defined in Florida regulation Rule 62-210.200(187), F.A.C., as:

- (a) With respect to any PSD pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero (0):
 - 1. The increase in emissions from a particular physical change or change in the method of operation as calculated pursuant to paragraph 62-212.400(2)(a), F.A.C.; and
 - 2. Any other increases or decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are creditable. Baseline actual emissions for calculating increases and decreases under this subparagraph shall be determined as provided in the definition of ‘baseline actual emissions,’ except paragraphs (a)3. and (b)4. of such definition shall not apply.
- (b) An increase or decrease in actual emissions is contemporaneous with the increase with the increase from the particular change only if it occurs between:
 - 1. The date five years before construction on the particular change commences; and
 - 2. The date that the increase from the particular change occurs.”
- (c) An increase or decrease in actual emissions is creditable only if the Department has not relied on it in issuing a permit for the source pursuant to Rule 62-212.400 or 62-212.500, F.A.C., which permit is in effect when the increase in actual emissions from the particular change occurs.
- (d) An increase or decrease in actual emissions of sulfur dioxide, particulate matter, or nitrogen oxides that occurs before the applicable minor source baseline date is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available.
- (e) An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.
- (f) A decrease in actual emissions is creditable only to the extent that:
 - 1. The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;
 - 2. It is federally enforceable as a practical matter at and after the time that actual construction on the particular change begins; and
 - 3. It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.
- (g) An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days.

SECI will permanently remove one of the two Existing SGS Units from service coincident with the commercial operation of SCCF. A federally enforceable permit condition that permanently removes the Existing SGS Units from service will be effective prior to commencement of construction and ensure that the emission decrease is creditable. In addition, the emission decrease will have the same qualitative significance for public health and welfare as the emission increase from SCCF.

Step 2 of the PSD NSR applicability analysis was conducted based on calculating the net emissions increase considering removing from service either Existing SGS Unit 1 or 2. Tables 3-4 and 3-5 provide summaries of the netting analysis based on removing Unit 1 or 2 from service, respectively. As shown, the results of this netting analysis indicate SCCF will have a net emissions increase greater than the PSD SER for VOCs only when considering the permanent removal from service of either Existing SGS Unit 1 or 2. Other pollutants will have a net emissions *decrease* and will not be subject to PSD applicability.

The following subsection provides a detailed description of how baseline actual emissions were determined for each pollutant. Appendix C provides a summary of the netting analysis and detailed baseline actual emission calculations. Tables C-1 through C-10 provide emission calculations based on permanently retiring Existing SGS Unit 1 and Tables C-11 through C-20 provide emissions calculations based on permanently removing from service Existing SGS Unit 2.

3.3.3 Baseline Actual Emissions—SGS Unit 1 or 2

Baseline actual emissions is defined in Rule 62-210.200(28), F.A.C., in part, as:

The rate of emissions, in tons per year, of a PSD pollutant, as follows:
(a) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding the date a complete permit application is received by the Department.

The definition allows a different consecutive 24-month period to be used for each unit and pollutant.

Table 3-4. SCCF Net Emissions Increase Compared to PSD SERs (Based on Shutdown of Existing SGS Unit 1)

Pollutant	Project Net Emissions Increase (tpy)	PSD SER (tpy)	PSD Applicability
CO	-660	100	No
NO _x	-376	40	No
SO ₂ *	-4,544	40	No
PM (filterable only)	-126	25	No
PM ₁₀ (filterable and condensable)	-520	15	No
PM _{2.5} (filterable and condensable)	-520	10	No
Ozone/VOC	75	40	Yes
Lead	Neg.	0.6	No
Fluorides	Not present	3	No
H ₂ SO ₄ mist	-55	7	No
Hydrogen sulfide	Not present	10	No
Total reduced sulfur (including hydrogen sulfide)	Not present	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Not present	10	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not present	3.5 × 10 ⁻⁶	No
Municipal waste combustor metals (measured as PM)	Not present	15	No
Municipal waste combustor acid gases (measured as SO ₂ and hydrogen chloride)	Not present	40	No
Municipal solid waste landfills emissions (measured as nonmethane organic compounds)	Not present	50	No
Mercury	Negligible	0.1	No
For the pollutants listed above, and for major stationary sources locating within 10 km of a Class I area having an impact equal to or greater than 1 µg/m ³ , 24-hour average	Not applicable	Any amount	No
GHGs (as CO ₂ e)	-165,053	75,000	No

*Baseline actual emissions were conservatively calculated using 0.25 lb/MMBtu based on the SO₂ permit emission limit effective on March 1, 2016. All monthly baseline actual SO₂ emissions, in units of tons, which were less than 0.25 lb/MMBtu, were not adjusted, and actual SO₂ emissions were used. All monthly SO₂ actual emissions considered in establishing the baseline actual SO₂ emissions reflect a maximum emissions rate of 0.25 lb/MMBtu.

Sources: R. 62-210.200(256), F.A.C.
SECI, 2017.
ECT, 2017.

Table 3-5. SCCF Net Emissions Increase Compared to PSD SERs (Based on Shutdown of Existing SGS Unit 2)

Pollutant	Project Net Emissions Increase (tpy)	PSD SER (tpy)	PSD Applicability
CO	-656	100	No
NO _x	-261	40	No
SO ₂ *	-4,676	40	No
PM (filterable only)	-119	25	No
PM ₁₀ (filterable and condensable)	-518	15	No
PM _{2.5} (filterable and condensable)	-518	10	No
Ozone/VOC	75	40	Yes
Lead	Neg.	0.6	No
Fluorides	Not present	3	No
H ₂ SO ₄ mist	-57	7	No
Hydrogen sulfide	Not present	10	No
Total reduced sulfur (including hydrogen sulfide)	Not present	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Not present	10	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not present	3.5 × 10 ⁻⁶	No
Municipal waste combustor metals (measured as PM)	Not present	15	No
Municipal waste combustor acid gases (measured as SO ₂ and hydrogen chloride)	Not present	40	No
Municipal solid waste landfills emissions (measured as nonmethane organic compounds)	Not present	50	No
Mercury	Negligible	0.1	No
For the pollutants listed above, and for major stationary sources locating within 10 km of a Class I area having an impact equal to or greater than 1 µg/m ³ , 24-hour average	Not applicable	Any amount	No
GHGs (as CO ₂ e)	-206,167	75,000	No

*Baseline actual emissions were conservatively calculated using 0.25 lb/MMBtu based on the SO₂ permit emission limit effective on March 1, 2016. All monthly baseline actual SO₂ emissions, in units of tons, which were less than 0.25 lb/MMBtu, were not adjusted, and actual SO₂ emissions were used. All monthly SO₂ actual emissions considered in establishing the baseline actual SO₂ emissions reflect a maximum emissions rate of 0.25 lb/MMBtu.

Sources: R. 62-210.200(256), F.A.C.
SECI, 2017.
ECT, 2017.

Appendix C provides detailed calculations of baseline actual emissions for Existing SGS Units 1 and 2. Table C-1 provides the summary results of the netting analysis for Existing SGS Unit 1. Tables C-2 through C-10 provide the detailed calculations for each pollutant. Table C-11 provides the summary results of the netting analysis for Existing SGS Unit 2. Tables C-12 through C-20 provide the detailed calculations for each pollutant.

For NO_x, SO₂, and CO₂, baseline actual emissions were calculated based on reported emissions data obtained from EPA's Clean Air Market Division (CAMD) database. These reported monthly emissions were based on continuous emissions monitoring system (CEMS) data reported under EPA's Acid Rain Program (ARP) and Mandatory Greenhouse Gas Reporting Rule. Since the reported emissions were based on actual CEMS data, the emissions include periods of startup and shutdown. Monthly emissions data was obtained for the five-year period from November 2012 through October 2017, as this represents the five-year period immediately preceding the anticipated date a complete permit application is received by FDEP. The highest 24-month annual average emission rate in tons per year was used as the baseline actual emissions for each pollutant and for each unit.

Tables C-2 and C-3 provide NO_x and SO₂ baseline actual emissions for Existing SGS Unit 1. Table C-4 provides CO₂e baseline actual emissions for Existing SGS Unit 1. GHG emissions (expressed as CO₂e) also include CH₄ and nitrous oxide (N₂O) emissions. Baseline actual CH₄ and N₂O emissions were calculated based on the actual heat input of each unit multiplied by the default emission factors, in units of pounds per million British thermal units (lb/MMBtu), obtained from Table C-2 to Subpart C of Part 98, Mandatory GHG Reporting Rule. The CH₄ and N₂O baseline actual emission calculations are provided in Table C-5. It is important to note that the same 24-month period that was used to determine the CO₂ baseline actual emissions that was used to obtain the heat input for calculating CH₄ and N₂O emissions. Therefore, the CO₂, CH₄ and N₂O emissions used to calculate the baseline actual GHG emission are based on the same 24-month period.

Table C-6 provides the baseline actual emissions for PM, PM₁₀ and PM_{2.5} for Existing SGS Unit 1. PM, PM₁₀ and PM_{2.5} baseline actual emissions were calculated based on the actual monthly heat input multiplied by a unit-specific emission factor obtained from stack tests performed on Existing

SGS Unit 1. Four quarterly stack tests were performed on Existing SGS Unit 1 during 2016. The results of these stack tests were averaged to obtain a PM/ PM₁₀/PM_{2.5} emission factor of 0.01825 lb/MMBtu for Existing SGS Unit 1. The results of the stack tests and the emission factor were based on the filterable portion only. PM emissions are based on the filterable portion only while PM₁₀ and PM_{2.5} emission include both filterable and condensable portions of particulate matter.

Table C-7 provides the baseline actual emissions for condensable particulate matter (CPM) for Existing SGS Unit 1. CPM emissions were calculated based on the actual heat input of each unit multiplied by the CPM emission factor obtained from AP-42, Table 1.1-5. It is important to note that the same 24-month period that was used to determine the filterable PM/PM₁₀/PM_{2.5} baseline actual emissions that was used to calculate the CPM baseline actual emissions. Therefore, the filterable PM/ PM₁₀/PM_{2.5} emissions and the CPM emissions used to calculate the baseline actual PM₁₀/PM_{2.5} emissions are based on the same 24-month period.

Table C-8 provides baseline actual emissions for CO for Existing SGS Unit 1 for the five highest 24-month annual average periods. Baseline actual CO emissions were based on monthly CO emission data measured and recorded by CO process analyzers for plant efficiency and optimization purposes.

Table C-9 provides the baseline actual VOC emissions for Existing SGS Unit 1. Baseline actual VOC emissions were calculated based on the actual monthly heat input multiplied by an emission factor, 0.017 lb/ton of coal, obtained from the average of three stack test runs performed on Existing SGS Unit 1 in 2010. It should be noted that previous Annual Operating Reports submitted during the previous 5 year baseline actual review period used a higher VOC emission factor of 0.06 lb/ton of coal based on AP-42 in order to conservatively report annual VOC emissions. SECI used a stack test-based emission factor to conform to FDEP guidance regarding the higher prioritization of site-specific data for emissions inventories. The stack-based emission factor is also a more conservative approach in assessing PSD applicability for VOC emissions as it is considerably lower than the AP-42 emission factor. As previously mentioned, the SCCF Project triggers PSD review for VOC emissions only.

Table C-10 provides the baseline actual sulfuric acid mist (SAM) emissions for Existing SGS Unit 1. Baseline actual SAM emissions were calculated based on the actual monthly heat input multiplied by an emission factor, 0.01 lb/MMBtu, obtained from site specific measurement data from Existing SGS Unit 1 between 2012 and 2017.

Tables C-12 through C-20 provide the detailed pollutant baseline actual emission calculations as described above for Existing SGS Unit 2.

3.3.4 Other Contemporaneous Creditable Emissions

The net emission increase analysis must also account for all other contemporaneous creditable increases or decreases in actual emissions that occurred during the contemporaneous period. The contemporaneous period is defined as the period commencing 5 years before construction on the particular change commences and ending when the emissions increase from the project occurs.

Since it is projected that construction of SCCF will commence between mid-2019 and early 2020, the beginning of the contemporaneous period is will be between mid-2014 and early 2015. The contemporaneous period will end when the emission increase from the SCCF occurs. SCCF is currently scheduled to commence operation following a reasonable shakedown period, in fourth quarter of 2021 or early 2022; therefore, this date will establish the end of the contemporaneous period.

There have been several air permitting actions since the commencement of the contemporaneous period in 2014.

- 1070025-019-AC was issued September 5, 2012, and authorized physical and operational improvements to the scrubbers on SGS Units 1 and 2, eliminated petroleum coke fuel, and established a more stringent SO₂ emissions limit for SGS Units 1 and 2. This new SO₂ emissions limit, which reduced SO₂ emissions from 0.6 to 0.25 lb/MMBtu, had an effective date of March 1, 2016, which falls within the contemporaneous period.
- 1070025-022-AC was issued on January 13, 2015, and authorized the replacement of baghouses with a dry fogging suppression system. The purpose of this air construction permit was to control fugitive dust emission from the handling and

storage of coal using a dry fogging system that utilizes less water as opposed to the existing baghouses. The control efficiency of the dry fogging system was deemed to be the same as the baghouses and therefore did not result in an increase or decrease in emissions.

- 1070025-023-AV was issued on February 13, 2015, and was a Title V Air Operation Permit Renewal which incorporated 1070025-022-AC.
- 1070025-024-AV requesting a one-year extension to the Mercury and Air Toxics Standards (MATS) compliance date.
- 1070025-025-AV was an administrative correction to the Title V Air Operation Permit, 1070025-023-AV to correct an SO₂ emission limit.
- 1070025-026-AC was issued on December 14, 2016, and authorized the installation of a dry fogging suppression system at three additional transfer points, which utilized baghouses to control fugitive dust emission from the handling and storage of coal.
- 1070025-027-AV was issued February 27, 2017, and was a Title V Air Operation Permit Revision to incorporate 1070025-025-AV and 1070025-026-AC.

Based on the permitting history at SGS, there have been no increases in actual emissions that are contemporaneous with the Project and are creditable since the beginning of the contemporaneous period in the fourth quarter of 2014. In addition, while there have been additional decreases in actual emissions that are contemporaneous with the Project, and are creditable, SECI does not rely on them for this netting analysis.

3.3.5 Netting Analysis Results

The results of the PSD NSR netting analysis concludes SCCF will be subject to PSD applicability for VOC emissions only. This netting analysis is valid whether SECI elects to permanently remove from service Existing SGS Unit 1 or 2. There will be a net emissions decrease for all other pollutants.

3.4 PSD Requirements

3.4.1 Control Technology Review

Pursuant to Rule 62-212.400(4)(c), F.A.C., an analysis of BACT is required for applicable pollutants with a net emissions increase equal to or greater than the PSD significant emissions rate levels. As defined by Rule 62-210.200(32), F.A.C., BACT is:

“an emissions limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account: (1) energy, environmental, and economic impacts, and other costs, (2) all scientific, engineering, and technical material and other information available to the Department, and (3) the emissions limiting standards or BACT determinations of Florida and any other state, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.”

BACT determinations are made on a case-by-case basis as part of the FDEP NSR process and apply to each pollutant with a net emissions increase that exceeds the PSD SER thresholds shown in Table 3-4 and 3-5. All emissions units involved in a major modification that cause a net emissions increase in excess of the PSD SER must undergo BACT analysis. Because each applicable pollutant must be analyzed, particular emissions units may undergo BACT analysis for more than one pollutant.

BACT is defined in terms of a numerical emissions limit. This numerical emissions limit can be based on the application of air pollution control equipment; specific production processes, methods, systems, or techniques; fuel cleaning; or combustion techniques. BACT limitations may not exceed any applicable federal NSPS, national emissions standard for hazardous air pollutants (NESHAP), or any other emissions limitation established by state regulations.

BACT analyses must be conducted using the following five step *top-down* approach:

1. All available control technology alternatives are identified based on knowledge of the particular industry of the applicant, control technology vendors, technical journals and reports, and previous control technology permitting decisions for other identical or similar sources.
2. The identified available control technologies are evaluated for technical feasibility. If a control technology has been installed and operated successfully on the type of source under review, it is considered demonstrated and technically feasible. An

undemonstrated control technology may be considered technically feasible if it is available and applicable. A control technology is considered available if it can be obtained commercially (i.e., the technology has reached the licensing and commercial sales phase of development). An available control technology is applicable if it can reasonably be installed and operated on the source type under consideration. Undemonstrated available control technologies that are determined to be technically infeasible, based on physical, chemical, and engineering principals, are eliminated from further consideration.

3. The technically feasible technology alternatives are rank-ordered by stringency into a control technology hierarchy.
4. The hierarchy is evaluated starting with the *top*, or most stringent alternative, to determine economic, environmental, and energy impacts and to assess the feasibility or appropriateness of each alternative as BACT based on site-specific factors. If the top control alternative is accepted as BACT from an economic and energy standpoint, evaluation of energy and economic impacts is not required since the only reason for conducting these assessments is to document the rationale for rejecting an alternative technology as BACT. Instead, the applicant proceeds to evaluate the top case control technology for impacts of unregulated air pollutants or impacts in other media (i.e., collateral environmental impacts). If there are no issues regarding collateral environmental impacts, the BACT analysis is complete, and the top case control technology alternative is proposed as BACT. If the top control alternative is not applicable due to adverse energy, environmental, or economic impacts, it is rejected as BACT and the next most stringent control alternative is then considered.
5. This evaluation process continues until an applicable control alternative is determined to be both technologically and economically feasible, thereby defining the emissions level corresponding to BACT for the evaluated pollutant.

This five-step procedure for conducting a BACT analysis is described in Chapter B of EPA's Draft New Source Review Manual dated October 1990.

3.4.2 Ambient Air Quality Monitoring

In accordance with the PSD requirements of Rule 62-212.400(7), F.A.C., any application for a PSD permit must contain, for each pollutant subject to review, an analysis of ambient air quality data in the area affected by the proposed major stationary source or major modification. The affected pollutants are those which the source would potentially emit in significant amounts (i.e., those that exceed the PSD significant emissions rate thresholds shown in Table 3-4 and 3-5).

Preconstruction ambient air monitoring for a period of up to 1 year is generally required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance (QA) requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided by EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (1987a).

Rule 62-212.400(3)(e), F.A.C., provides an exemption that excludes or limits the pollutants for which an air quality monitoring analysis is conducted. This exemption states that a proposed facility will be exempt from the monitoring requirements of Rule 62-212.400(7), F.A.C., with respect to a particular pollutant if the emissions increase of the pollution from the new source would cause, in any area, air quality impacts less than the PSD *de minimis* ambient impact levels presented in Rule 62-212.400(3)(e)1., F.A.C. (see Table 3-6). In addition, an exemption may be granted if the air quality impacts due to existing sources in the area of concern are less than the PSD *de minimis* ambient impact levels. The SCCF net VOC emissions are less than the PSD threshold for ambient air monitoring; therefore, SCCF is exempt from air quality monitoring.

Table 3-6. PSD *De Minimis* Ambient Impact Levels

Averaging Time	Pollutant	<i>De Minimis</i> Level (µg/m ³)
Annual	NO ₂	14
Quarterly	Lead	0.1
24-Hour	PM ₁₀	10
	SO ₂	13
	Mercury	0.25
	Fluorides	0.25
8-Hour	CO	575
1-Hour	Total reduced sulfur	10
	Hydrogen sulfide	0.2
	Reduced sulfur compounds	10
Not applicable	Ozone	100 tpy of VOC emissions

Source: R. 62-212.400(3)(e)1., F.A.C.

3.4.3 Ambient Impact Analysis

An air quality or source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the net increase in emissions exceeds the significant emissions rates (see Tables 3-4 and 3-5). The addition of SCCF and the permanent removal from service of either Unit 1 or 2 will result in a net decrease for all regulated pollutants except for VOC. VOC is a precursor to ozone.

Ozone, however, is one pollutant for which a source impact analysis is not normally required in order to show compliance with the National Ambient Air Quality Standards (NAAQS). Ozone is formed in the atmosphere as a result of complex photochemical reactions. Models for ozone are not typically conducted for single-source permitting due to complexity involving computationally intensive models. Instead, they are applied to entire urban areas. As such, a source impact analysis is not required.

However, the potential effect the VOC emissions would have on the surrounding areas was evaluated. The SGS facility is located in a rural area, where the naturally occurring VOC emissions are anticipated to be significantly higher in comparison to the potential VOC emissions from SCCF. The nearest ozone monitor, located in a similar rural environment, to SGS is located in Micanopy, Florida (Site ID 120013011). The monitor design value for the area is 58.7 ppb, for the period 2014 through 2016, which is well below the 2015 8-hour ozone NAAQS of 70 ppb.

In addition, the decrease in NO_x emissions and subsequent decrease in ozone formation due to NO_x emissions will offset entirely or significantly any increase in ozone formation due to the increase in potential VOC emissions.

Therefore, SCCF is not anticipated to have a significant impact on surrounding ozone concentration as a result of the relatively small increase in potential VOC emissions.

3.4.4 Additional Impact Analyses

Rule 62-212.400(8), F.A.C., requires additional impact analyses for three areas: associated growth, soils and vegetation impact, and visibility impairment. The level of analysis for each area should be commensurate with the scope of the Project. A more extensive analysis would be conducted for projects having large emissions increases than those that will cause a small increase in emissions.

The growth analysis generally includes:

- A projection of the associated industrial, commercial, and residential growth that will occur in the area.
- An estimate of the air pollution emissions generated by the permanent associated growth.
- An air quality analysis based on the associated growth emissions estimates and the emissions expected to be generated directly by the new source or modification.

The soils and vegetation analysis is typically conducted by comparing projected ambient concentrations for the pollutants of concern with applicable susceptibility data from the air pollution literature. For most types of soils and vegetation, ambient air concentrations of criteria

pollutants below the NAAQS will not result in harmful effects. Sensitive vegetation and emissions of toxic air pollutants could necessitate a more extensive assessment of potential adverse effects on soils and vegetation.

The visibility impairment analysis pertains particularly to Class I area impacts and other areas where good visibility is of special concern. A quantitative estimate of visibility impairment is conducted, if warranted by the scope of the Project. Section 6.0 provides the additional impact analyses for SCCF.

4.0 State and Federal Emissions Standards

4.1 New Source Performance Standards

Section 111 of the CAA, Standards of Performance of New Stationary Sources, requires EPA establish federal emissions standards for source categories that cause or contribute significantly to air pollution. These standards require EPA to impose limitations based on the best systems of emission reductions that have been adequately demonstrated technologies, taking into account the cost of such technology and any other non-air quality, health, and environmental impact and energy requirements. These standards apply to sources that have been constructed or modified since the proposal of the standard. Since December 23, 1971, EPA has promulgated more than 75 standards. The NSPS are codified in 40 CFR 60.

Major components of SCCF include two CTG/HRSG units, one 16-cell mechanical draft cooling tower, two fuel gas dew point heaters, one emergency fire water pump diesel engine, natural gas piping, and components and circuit breakers that contain SF₆ and electrical insulating gas. NSPS that are potentially applicable to these Project emissions sources are discussed in the following subsections.

4.1.1 NSPS Subpart KKKK—Stationary CTGs

Subpart KKKK establishes emissions limits for CTG/HRSG units that commenced construction, modification, or reconstruction after February 18, 2005, and have a heat input at peak load equal to greater than 10.7 gigajoules (10 MMBtu/hr) based on the HHV of the fuel. HRSGs and duct burners regulated under Subpart KKKK are exempt from the requirements of NSPS Subparts Da, Db, and Dc. Also, because the CTG is subject to KKKK, it is exempt from NSPS subpart GG.

The affected facility under Subpart KKKK is a stationary CTG, which is defined by Subpart KKKK as:

all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and subcomponents comprising any

simple cycle stationary combustion turbine, any regenerative/ recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

NSPS Subpart KKKK specifies emissions limitations, monitoring, reporting, and recordkeeping requirements for NO_x and SO₂. Applicable NSPS Subpart KKKK emissions standards are summarized as follows:

- NO_x—15 ppmvd at 15-percent oxygen gas, or 0.43 pound per megawatt-hour (lb/MWh) gross energy output (CTG loads greater than or equal to 75 percent of peak load).
- NO_x—96 ppmvd at 15-percent oxygen gas, or 4.7 lb/MWh gross energy output (CTG loads less than 75 percent of peak load).
- SO₂—0.90 lb/MWh gross energy output, or 0.060 pound per million British thermal units (lb/MMBtu).

SCCF CTG/HRSGs will have NO_x and SO₂ emissions well below the NSPS Subpart KKKK emissions standards and will comply with the applicable monitoring, reporting, and performance test requirements of NSPS Subpart KKKK.

4.1.2 NSPS Subpart IIII—Stationary Compression Ignition Internal Combustion Engines

NSPS Subpart IIII is applicable to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, where the CI ICE are manufactured after July 1, 2006, for certified National Fire Protection Association fire water pump engines.

NSPS Subpart IIII specifies emissions limitations, monitoring, reporting, and recordkeeping requirements for NO_x, CO, NMHC, and PM. Applicable NSPS Subpart IIII emissions standards for the SCCF emergency fire water pump diesel engine are summarized in Table 4 of NSPS Subpart IIII for all pollutants and are listed below for the proposed 250-hp engine:

<u>Pollutant</u>	<u>Emissions Standard</u>
NMHC + NO _x	4.0 g/kW-hr (3.0 g/hp-hr)
CO	3.5 g/kW-hr (2.6 g/hp-hr)
PM	0.20 g/kW-hr (0.15 g/hp-hr)

The SCCF emergency fire water pump diesel engine will be certified by the manufacturer to meet these emission standards. Other requirements include combusting only ULSD fuel, limiting the hours of operation to 100 hours per year for routine maintenance and testing, and maintaining the engine in accordance with the manufacturer’s recommendations.

4.1.3 NSPS Subpart TTTT—GHG Emissions for Electric Generating Units

NSPS Subpart TTTT is applicable to any steam generating unit, integrated gasification combined-cycle, or stationary CTG that commenced construction after January 8, 2014, or commenced modification or reconstruction after June 18, 2014, that:

- Has a base load rating greater than 250 MMBtu/hr of fossil fuel.
- Serves a generator(s) capable of selling greater than 25 MW of electricity to a utility power distribution system.

Newly constructed or reconstructed stationary CTGs that supply more than their design efficiency or 50 percent, whichever is less, times their potential net-electric sales on both a 12-operating month and a three-year rolling average and combusts more than 90 percent natural gas on a heat input basis must not exceed 1,000 lb/MWh (gross) of CO₂ at all times including periods of startup and shutdown.

Compliance with this CO₂ emissions limit can be demonstrated by either installing, calibrating, and operating a continuous emissions monitoring system (CEMS) for CO₂ emissions or monitoring the fuel flow to the turbines and using the methods as outlined in Appendix G, Part 75

The SCCF will comply with the applicable requirements of NSPS Subpart TTTT.

4.2 National Emissions Standards for HAPs

Florida relies on the requirements of the CAA with respect to the regulation of HAPs (also known as toxic air pollutants). These federal requirements include a comprehensive set of technology-based emissions standards referred to as NESHAP. These standards establish HAP emissions limitations for a wide variety of industrial source categories. Recent NESHAP (i.e., those adopted after the 1990 CAA Amendments) reflect maximum achievable control technology (MACT). The following provides a discussion of the NESHAP program and its applicability to SCCF.

Section 112 of the CAA contains the provisions that address the control of HAP emissions, or air toxics. Section 112 includes provisions for the promulgation of NESHAP, or MACT standards, as well as several related programs to enhance and support the NESHAP program. Section 112 requires EPA to publish and regularly update (at least every eight years) a list of all categories and subcategories of major and area sources that emit HAPs. The Section 112(c) list of source categories was initially published in the Federal Register on July 16, 1992, and has been periodically revised thereafter. EPA must promulgate regulations establishing emissions standards (NESHAP) for each category or subcategory of major sources and area sources of HAPs that are listed pursuant to Section 112(c). The standards must require the maximum degree of emissions reduction that EPA determines to be achievable by each particular source category. Different criteria for MACT apply for new and existing sources. Less stringent standards, known as generally available control technology standards, are allowed at the EPA Administrator's discretion for area sources.

SGS is considered an existing major source of HAPs, which is defined as a source with potential HAP emissions greater than 10 tons per year for any individual HAP or greater than 25 tons per year for total HAPs. SGS will remain a major source of HAPs.

4.2.1 NESHAP Subpart DDDDD—National Emissions Standards for HAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

EPA promulgated a final NESHAP for industrial, commercial, and institutional boiler and process heaters at major sources (40 CFR 63, Subpart DDDDD) on February 1, 2013, with notice of final action on reconsideration effective November 20, 2015. Pursuant to 40 CFR 63.7485, the fuel gas

dew point heaters are considered process heaters located at a major source of HAPs and therefore are subject to Subpart DDDDD.

According to 40 CFR 63.7500(e), the fuel gas dew point heaters, which combust pipeline-quality natural gas exclusively, are not subject to the emissions limits in Tables 1 and 2 or 11 through 13 in Subpart DDDDD. The fuel gas dew point heaters are required to conduct a biennial tune-up as specified in 40 CFR 63.7540(a)(11).

4.2.2 NESHAP Subpart ZZZZ—Reciprocating Internal Combustion Engines

The source category list presently includes stationary reciprocating internal combustion engines (RICE). As required in Section 112 of the CAA, EPA initially promulgated a final NESHAP for stationary RICE (40 CFR 63, Subpart ZZZZ) on June 15, 2004. Subpart ZZZZ was subsequently amended on March 3, 2010, to address CI RICE located at area HAP sources. On January 30, 2013, EPA finalized amendments to Subpart ZZZZ.

Pursuant to 40 CFR 63.6590(c)(6), a new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake horsepower located at a major source of HAPs, must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR Part IIII for compression ignition engines. Therefore, the emergency fire water pump diesel engine will demonstrate compliance with NESHAP Subpart ZZZZ by demonstrating compliance with NSPS Subpart IIII.

4.2.3 NESHAP Subpart YYYY—Stationary CTGs

EPA promulgated a final NESHAP for stationary CTGs (40 CFR 63, Subpart YYYY) on March 5, 2004. On April 7, 2004, EPA proposed to delete lean premix gas-fired stationary CTGs, diffusion flame gas-fired CTGs, emergency CTGs, and stationary CTGs located on the North Slope of Alaska from the Section 112(c) list of HAP source categories. On August 18, 2004, EPA stayed the effectiveness of two Subpart YYYY subcategories: lean premix and diffusion flame gas-fired turbines. This stay is still currently in effect; therefore, this NESHAP is not applicable to the SCCF CTGs.

4.3 Acid Rain Program

The overall goal of EPA's Acid Rain Program (ARP) is to achieve significant environmental and public health benefits through reductions in emissions of SO₂ and NO_x, the primary causes of acid rain. To achieve this goal at the lowest cost to society, the program employs both traditional and innovative, market-based approaches for controlling air pollution. In addition, the program encourages energy efficiency and pollution prevention.

Title IV of the CAA sets a goal of reducing annual SO₂ emissions by 10 million tons below 1980 levels. To achieve these reductions, the law requires a two-phase tightening of the restrictions placed on fossil fuel-fired power plants. Phase I began in 1995 and affected 263 units at 110 mostly coal-burning electric utility plants located in 21 eastern and midwestern states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I-affected units to 445. Phase II, which began in the year 2000, tightens the annual emissions limits imposed on these large, higher emitting plants and also sets restrictions on smaller, cleaner plants fired by coal, oil, and gas, encompassing more than 2,000 units in all. The program affects existing utility units serving generators with an output capacity of greater than 25 MW and all new utility units.

For SO₂, EPA's ARP introduced an allowance trading system that harnesses the incentives of the free market to reduce pollution. Under this cap-and-trade program, affected existing utility units (i.e., those in operation prior to November 15, 1990) are allocated allowances based on their historical fuel consumption and a specific emissions rate. Each allowance permits a unit to emit 1 ton of SO₂ during or after a specified year. For each ton of SO₂ emitted in a given year, one allowance is retired, that is, it can no longer be used. Allowances may be bought, sold, or banked. Anyone may acquire allowances and participate in the trading system. However, regardless of the number of allowances a source holds, it may not emit at levels that would violate federal or state limits set under Title I of the CAA to protect public health. During Phase II of the program (now in effect), the CAA set a permanent ceiling (or cap) of 8.95 million allowances for total annual SO₂ allowance allocations to utilities. This cap firmly restricts emissions and ensures environmental benefits will be achieved and maintained. New utility units (i.e., those that commence operation on and after November 15, 1990) are not allocated any SO₂ allowances and

must obtain such allowances annually from the ARP SO₂ allowance market in amounts equal to their actual SO₂ emissions rates.

The CAA also required a 2-million-ton reduction in NO_x emissions by the year 2000. A significant portion of this reduction has been achieved by coal-fired utility boilers that will be required to install low NO_x burner technologies and meet new emissions standards. EPA's ARP NO_x emissions reduction requirements are only applicable to existing utility units (i.e., those in operation prior to November 15, 1990).

SCCF CTG/HRSG units are subject to the ARP, since they are new utility units (i.e., commenced operation after November 15, 1990) and will serve a generator that produces electricity for sale.

4.4 Cross-state Air Pollution Rule

On September 7, 2016, EPA issued the final update to the Cross-State Air Pollution Rule (CSAPR) for the 2008 ozone NAAQS. This rule, also referred to as the Transport Rule, will reduce ozone season emissions from power plants in 22 states in the eastern United States starting in May 2017. Florida is not one of the 22 states identified in CSAPR as a state having sources that contribute to transport of ozone pollution to downwind states. Therefore, the existing SGS and proposed SCCF are not subject to the requirements of CSAPR.

4.5 Florida Emissions Standards

FDEP emissions standards for stationary sources are contained in Chapter 62-296, F.A.C., Stationary Sources, Emissions Standards. General pollutant emissions limit standards are included in Rule 62-296.320, F.A.C. Rules 62-296.401 through .418, F.A.C., specify emissions standards for 15 categories of sources. Rules 62-296.500 through .570, F.A.C., establish RACT requirements for VOC- and NO_x-emitting facilities. RACT requirements for lead and PM are found in Rules 62-296.600 through .605 and 62-296.700 through .712, F.A.C., respectively.

With respect to SCCF emissions sources, the general Rule 62-296.320(4)(b), F.A.C., visible emissions limitation of 20-percent opacity will apply to all point (i.e., stack) emissions sources.

Reasonable precautions to prevent unconfined PM emissions will be required pursuant to Rule 62-296.320(4)(c), F.A.C.

None of the source-specific emissions standards specified in Rules 62-296.401 through .418, F.A.C., are applicable to the proposed SCCF.

SCCF emissions sources will comply with the applicable Florida emissions standards noted herein.

5.0 Control Technology Review

5.1 Applicable Air Pollution Control Requirements

The proposed Project is subject to review with respect to the following control technology requirements:

- BACT for VOCs, which is the only pollutant that exceeds PSD SER thresholds specified in Rule 62-210.200, F.A.C, for which Putnam County is classified as attainment.

BACT requirements apply to each air emissions source at the facility that emits that particular pollutant. These analyses are discussed in the following subsections

5.2 Top-down BACT Analysis

A BACT analysis is required for any pollutants subject to the PSD regulations. BACT is defined in the PSD regulations 40 CFR 52.21(b)(12) as, “an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for pollutant subject to regulation under BACT, which would be emitted from any proposed major stationary source or major modification the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.”

Both EPA and FDEP recommend a top-down approach to the BACT analysis. BACT analyses were performed in accordance with EPA’s top-down method. The first step in the top-down BACT procedure is the identification of available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, postprocess stack

controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information used to identify control alternatives include:

- EPA’s RBLC database.
- Vendor information.
- ECT’s experience with similar projects.

Following the identification of available control technologies, the second step in the analysis is to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the draft EPA NSR Workshop Manual (EPA, 1990). The third step in the top-down BACT process is the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness.

An assessment of energy, environmental, and economic impacts is then performed as step four. The economic analysis procedures can be found in the Office of Air Quality Planning and Standards Control Cost Manual (EPA, 2002). The fifth and final step is the selection of a BACT emissions limitation or a design, equipment, work practice, operational standard, or combination thereof corresponding to the most stringent, technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds.

If the most stringent or top control technology is selected, an assessment of energy and economic impacts is not required. In this case, a review of collateral environmental impacts is conducted to determine if selection of a less stringent alternative control technology is warranted. If there are no issues regarding collateral environmental impacts, the top control technology is proposed as BACT, and the BACT analysis is concluded.

The following sections provide control technology analyses using the five-step top-down BACT method for VOC emissions for all equipment emitting VOC emissions subject to this analysis.

5.3 CTG/HRSG BACT Analysis—VOCs

VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Because higher combustion temperatures will

increase oxidation rates, emissions of VOC will generally increase during turbine partial load conditions when combustion temperatures are lower. Generally, decreased combustion zone temperature due to the injection of water or steam for NO_x control will also result in an increase in VOC emissions. An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in VOC emissions rates. Emissions of NO_x and VOC are inversely related (i.e., decreasing NO_x emissions will result in an increase in VOC emissions). Accordingly, CTG vendors have had to consider the competing factors involved in NO_x and VOC formation to develop units that achieve acceptable emissions levels for both pollutants.

5.3.1 Available VOC Control Technologies (Step 1)

There are two available technologies for controlling VOC from CTGs: combustion process design and oxidation catalysts.

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of VOC to CO₂ and water at temperatures lower than would be necessary for oxidation without a catalyst. The design operating temperature range for oxidation catalysts is between 650 and 1,150°F.

Efficiency of VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant VOC oxidation will occur at any temperature above approximately 900°F. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst, which will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time, which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed.

VOC removal efficiency will vary with the species of hydrocarbon. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical VOC control efficiency using oxidation catalyst is in the range of 30 to 50 percent.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica (typically present in fuel oil) will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies. Oxidation catalysts are also nonselective and will oxidize other compounds in addition to VOC. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been oxidized to SO_2 in the combustion process will be further oxidized by the catalyst to sulfur trioxide (SO_3). Higher SO_3 concentrations increase the potential for formation of ammonia salt particles and H_2SO_4 mist. These substances may condense and stick to the ductwork and stack, resulting in corrosion and increased maintenance. Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered appropriate for combustion devices fired with fuels containing appreciable amounts of sulfur.

5.3.2 VOC BACT Technical Feasibility (Steps 2 and 3)

Both combustion process design and oxidation catalysts are considered technically feasible for the facility's CTGs/HRSGs, despite the potential drawbacks cited previously for the oxidation catalyst. However, the application of an oxidation catalyst, along with good combustion practices, represents the top level of control and, therefore, BACT for the CTGs/HRSGs.

5.3.3 Proposed VOC BACT Emissions Limit (Steps 4 and 5)

To determine the BACT VOC emissions limit for the CTGs/HRSGs, EPA's RBLC database was queried for large CTGs firing natural gas. BACT determinations were obtained for the past ten years and are summarized in Appendix D, Table D-1.

The lowest VOC concentration for a natural gas-fired CTG without duct firing listed in the RBLC database is 0.3 ppmvd at 15-percent oxygen for the Chouteau Power Plant in Mayes County, Oklahoma. There are numerous records of VOC emissions rates ranging from 0.7 to 1.9 ppmvd at 15-percent oxygen. However, the majority are either draft determinations of which achievable emissions have not yet been demonstrated, or which represent LAER determinations. Of other non-draft BACT determinations for natural gas-fired CTGs without duct firing listed in the RBLC database, no determination is less than 1 ppmvd at 15-percent oxygen.

The most recent VOC BACT determination for a GE 7HA.02 CTG firing natural gas was issued by FDEP for the Okeechobee Clean Energy Center. The VOC BACT limit for Okeechobee Clean Energy Center is 1.0 ppmvd at 15-percent oxygen for all operating loads without duct burner firing. Other VOC BACT determinations list 2.0 ppmvd at 15-percent oxygen for all combustion turbine operating loads with duct burner firing.

The proposed VOC BACT emissions limit for the SCCF CTGs/HRSGs is 1.0 ppmvd without duct burner firing and 2.0 ppmvd with duct burner firing as summarized in Table 5-1. This proposed VOC emissions limit is consistent with typical BACT emissions limits for VOC. Compliance will be achieved through the exclusive use of pipeline-quality natural gas, GCP, and an oxidation catalyst. Compliance will be demonstrated by an initial stack test for VOC (average of three 1-hour stack tests) and a stack test for VOC conducted every 5 years upon Title V permit renewal.

Table 5-1. Proposed VOC BACT Emissions Limit for CTGs/HRSGs

Emissions Source	Proposed VOC BACT Emissions Limits, Three-Hour Average
Natural gas firing – CTG/HRSG (up to and including peak load operation without duct burner firing)	1.0 ppmvd*
Natural gas firing – CTG/HRSG (up to and including peak load operation with duct burner firing)	2.0 ppmvd*

*Corrected to 15-percent oxygen gas.

Sources: GE, 2017.
SECI, 2017

5.4 Fuel Gas Heaters BACT Analysis—VOCs

The fuel gas heaters are a relatively small combustion source, rated at 9.99 MMBtu/hr or less each heat input, which will fire natural gas exclusively. There are no combustion modifications or add-

on postcombustion processes typically applied to fuel gas heaters of this capacity. BACT determinations were obtained for the past ten years and are summarized in Appendix D, Table D-2.

The proposed VOC BACT for the fuel gas heaters is 0.005 lb/MMBtu based on the exclusive use of natural gas and good combustion practices. This emissions limit is typical for natural gas-fired combustion sources rated less than 10 MMBtu/hr.

5.5 Emergency Fire Water Pump Engine BACT Analysis—VOCs

The proposed VOC BACT emission limit for the emergency fire water pump engine will be compliance with the emissions limits of 40 CFR 60, Subpart IIII, NSPS for Stationary Compression Ignition Internal Combustion Engines, effective September 11, 2006. Nonmethane hydrocarbons emissions are included in the combined NO_x and NMHC emissions limits specified in Table 4 of Subpart IIII. Compliance with the NO_x and NMHC emissions limits will be demonstrated by obtaining a manufacturer's certified engine, the exclusive use of ULSD and limiting the hours of operation for routine maintenance and testing to 100 hr/yr.

6.0 Additional Impact Analyses³

A new or expanded industrial facility can also sometimes generate growth in other industrial or commercial operations needed to support the new/expanded facility. Given the SGS site's long-time use for power generation and the removal of one Existing Unit from service, the existing commercial infrastructure should be more than adequate to provide any support services that the proposed facility might require. Therefore, no air quality impacts due to associated industrial/commercial growth would be expected.

No visibility impairment at the local level is expected due to the fact that there will only be a net emissions increase of VOC emissions. All other regulated pollutants that could potentially impair visibility, including PM₁₀, PM_{2.5}, NO_x, and SO₂, will have a net emissions decrease.

Certain air pollutants in acute concentrations or chronic exposures can impact soils, vegetation, or wildlife resources. Soils impacts can result from SO₂ and NO_x deposition creating an acidic reaction or lowering of soil pH. In this case, the site soils are naturally acidic and Project SO₂ and NO_x emissions are not expected to adversely affect soils in the plant vicinity. There will be a net emissions decrease in SO₂ and NO_x emissions from SCCF.

Vegetation is sometimes affected by acute exposures to high concentrations of pollutants often resulting in foliar damage. Lower dose exposure over longer periods of time (chronic exposure) can often affect physiological processes within plants causing internal and external damage. Based on an evaluation of the literature for effects from SO₂, sulfuric acid (H₂SO₄) mist, NO_x, CO, and combinations of these pollutants (synergistic effects), there will be no impacts to regional vegetation due to the Project's net emissions decrease for these pollutants. In addition, any impacts from the relatively small increase in VOC emissions will be negligible.

³ R. 62-212.400(4)(e), (8)(a), (9), F.A.C.

Releases of air pollutants can also affect wildlife through inhalation, exposure through skin, or ingestion. However, based on comparatively low emissions levels and resulting insignificant Project impacts, natural dispersion of emissions, and mobility of wildlife, insignificant impacts to regional wildlife resources are expected. Again, overall, with the exception of VOC, the Project will result in a net emissions decrease.

Based on this assessment, Project emissions are not expected to cause harm to soils, vegetation, or wildlife.

Appendix A

FDEP Application for Air Permit—Long Form



Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: Seminole Electric Cooperative, Inc.	
2. Site Name: Seminole Generating Station	
3. Facility Identification Number: 1070025	
4. Facility Location... Street Address or Other Locator: 890 North Highway 17 City: Palatka County: Putnam Zip Code: 32177	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: James R. Frauen	
2. Application Contact Mailing Address... Organization/Firm: Seminole Electric Cooperative, Inc. Street Address: 16313 North Dale Mabry Highway City: Tampa State: Florida Zip Code: 33618	
3. Application Contact Telephone Numbers... Telephone: (813) 739 - 1213 ext. Fax: () -	
4. Application Contact E-mail Address: jffrauen@seminole-electric.com	

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3. PSD Number (if applicable):
2. Project Number(s):	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is being submitted to obtain: (Check one)

Air Construction Permit

- ☒ Air construction permit.
- ☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).
- ☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

- ☐ Initial Title V air operation permit.
- ☐ Title V air operation permit revision.
- ☐ Title V air operation permit renewal.
- ☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
- ☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

- ☐ Air construction permit and Title V permit revision, incorporating the proposed project.
- ☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

- ☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

This air construction permit application is for Seminole Combined-Cycle Facility (SCCF) a proposed new 1,183-MW (gross nominal), 1,050-MW (net nominal) natural gas-fired combined cycle combustion turbine facility, located on the existing Seminole Generating Station (SGS) property. SCCF will consist of two General Electric 7HA.02 combustion turbines arranged in a two-on-one combined-cycle configuration with fired heat recovery steam generator (HRSG). Ancillary equipment will include two fuel gas dew point heaters, emergency firewater pump engine and a 16-cell mechanical draft cooling tower. The SCCF is subject to PSD review for VOC only.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
009	Natural gas-fired combustion turbine with duct-fired HRSG	AC1A	\$7,500
010	Natural gas-fired combustion turbine with duct-fired HRSG	AC1A	N/A
011	Two ≤ 9.99 MMBtu/hr fuel gas heaters	AC1A	N/A
012	Emergency firewater pump engine	AC1A	N/A
013	16-Cell Wet mechanical draft cooling tower	AC1A	N/A

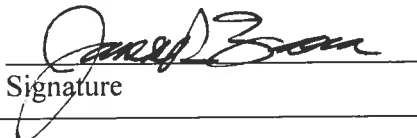
Application Processing Fee

Check one: ☒ Attached - Amount: \$ 7,500 ☐ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name: James R. Frauen
2. Owner/Authorized Representative Mailing Address... Organization/Firm: Seminole Electric Cooperative, Inc. Street Address: 16313 North Dale Mabry Highway City: Tampa State: Florida Zip Code: 33618
3. Owner/Authorized Representative Telephone Numbers... Telephone: (813) 739 - 1213 ext. Fax: () -
4. Owner/Authorized Representative E-mail Address: jffrauen@seminole-electric.com
5. Owner/Authorized Representative Statement: <i>I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.</i>  Signature <u>12-7-17</u> Date

APPLICATION INFORMATION

Application Responsible Official Certification

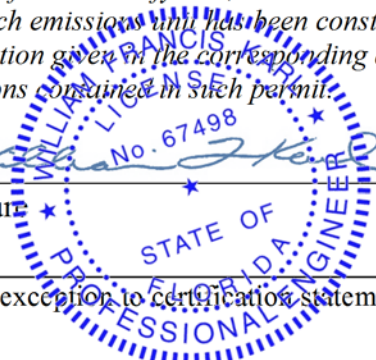
Not Applicable

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the “application responsible official” need not be the “primary responsible official.”

1. Application Responsible Official Name:
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source or CAIR source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: () - ext. Fax: () -
5. Application Responsible Official E-mail Address:
6. Application Responsible Official Certification: I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application. _____ Signature _____ Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: William F. Karl Registration Number: 67498
2. Professional Engineer Mailing Address... Organization/Firm: Environmental Consulting & Technology, Inc. Street Address: 3701 NW 98th St City: Gainesville State: FL Zip Code: 32606
3. Professional Engineer Telephone Numbers... Telephone: (352) 332 - 0444 ext. Fax: (352) 332 - 6722
4. Professional Engineer E-mail Address: wkarl@ectinc.com
5. Professional Engineer Statement: <i>I, the undersigned, hereby certify, except as particularly noted herein*, that:</i> <i>(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and</i> <i>(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.</i> <i>(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐ , if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.</i> <i>(4) If the purpose of this application is to obtain an air construction permit (check here ☒ , if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐ , if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.</i> <i>(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐ , if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.</i>  Signature _____ (seal) _____ Date <u>December 5, 2017</u>

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone East (km) 438.8 North (km) 3289.2		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) 29° 43' 59" N Longitude (DD/MM/SS) 81° 37' 58" W	
3. Governmental Facility Code: 0	4. Facility Status Code: Active	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: Chris Brew
2. Facility Contact Mailing Address... Organization/Firm: Seminole Electric Cooperative, Inc. Street Address: 890 North Highway 17 City: Palatka State: FL Zip Code: 32177
3. Facility Contact Telephone Numbers: Telephone: (386) 328 - 9255 ext. 2159 Fax: (813) 739 - 1487
4. Facility Contact E-mail Address: CBrew@seminole-electric.com

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: () - ext. Fax: () -
4. Facility Primary Responsible Official E-mail Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a “major source” and a “synthetic minor source.”

1.	☐ Small Business Stationary Source	☐ Unknown
2.	☐ Synthetic Non-Title V Source	
3.	☒ Title V Source	
4.	☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5.	☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6.	☒ Major Source of Hazardous Air Pollutants (HAPs)	
7.	☐ Synthetic Minor Source of HAPs	
8.	☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9.	☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10.	☒ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11.	☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12.	Facility Regulatory Classifications Comment: The following are applicable NSPS and NESHAPs: NSPS - 40 CFR Part 60 Subpart KKKK – Stationary Combustion Turbines Subpart IIII – Stationary Compression Ignition Internal Combustion Engines Subpart TTTT – Greenhouse Gas Emissions for Electric Generating Units NESHAP – 40 CFR Part 63 Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Source of HAPs Subpart ZZZZ – Reciprocating Internal Combustion Engines	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NO_x	A	No
CO	A	No
VOC	A	No
SO₂	A	No
PM	A	No
PM₁₀	A	No
PM_{2.5}	A	No
SAM	A	No
GHG	A	No
Lead	B	No
H015	(C) CLASS IS UNKNOWN	No
H027	(C) CLASS IS UNKNOWN	No
H046	(C) CLASS IS UNKNOWN	No
H053	(C) CLASS IS UNKNOWN	No
H054	(C) CLASS IS UNKNOWN	No
H106	(C) CLASS IS UNKNOWN	No
H107	(C) CLASS IS UNKNOWN	No
H114	(C) CLASS IS UNKNOWN	No
H150	(C) CLASS IS UNKNOWN	No
H162	(C) CLASS IS UNKNOWN	No
SAM	(C) CLASS IS UNKNOWN	No

FACILITY INFORMATION

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

Not Applicable

1. Pollutant Subject to Emissions Cap	2. Facility-Wide Cap [Y or N]? (all units)	3. Emissions Unit ID's Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

FACILITY INFORMATION

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)		
☒	Attached, Document ID: <u>Section 2.0</u>	☐	Previously Submitted, Date: _____
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)		
☒	Attached, Document ID: <u>Section 2.0</u>	☐	Previously Submitted, Date: _____
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)		
☒	Attached, Document ID: <u>Appendix E</u>	☐	Previously Submitted, Date: _____

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location:		
☒	Attached, Document ID: <u>Section 2.0</u>	☐	Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL):		
☒	Attached, Document ID: <u>Section 2.0</u>		
3.	Rule Applicability Analysis:		
☒	Attached, Document ID: <u>Section 4.0</u>		
4.	List of Exempt Emissions Units:		
☐	Attached, Document ID: _____	☒	Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification:		
☐	Attached, Document ID: _____	☒	Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.):		
☐	Attached, Document ID: _____	☒	Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.):		
☐	Attached, Document ID: _____	☐	Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.):		
☐	Attached, Document ID: _____	☒	Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.):		
☒	Attached, Document ID: <u>Section 6.0</u>	☐	Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.):		
☐	Attached, Document ID: _____	☒	Not Applicable

FACILITY INFORMATION

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications

Not Applicable

1. List of Exempt Emissions Units:

☐ Attached, Document ID: _____ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

Not Applicable

1. List of Insignificant Activities: (Required for initial/renewal applications only)

☐ Attached, Document ID: _____ ☐ Not Applicable (revision application)

2. Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought)

☐ Attached, Document ID: _____

☐ Not Applicable (revision application with no change in applicable requirements)

3. Compliance Report and Plan: (Required for all initial/revision/renewal applications)

☐ Attached, Document ID: _____

Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.

4. List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only)

☐ Attached, Document ID: _____

☐ Equipment/Activities Onsite but Not Required to be Individually Listed

☐ Not Applicable

5. Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only)

☐ Attached, Document ID: _____ ☐ Not Applicable

6. Requested Changes to Current Title V Air Operation Permit:

☐ Attached, Document ID: _____ ☐ Not Applicable

FACILITY INFORMATION

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1. Acid Rain Program Forms:

Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):

☒ Attached, Document ID: **Appendix F** ☐ Previously Submitted, Date: _____

☐ Not Applicable (not an Acid Rain source)

Phase II NO_x Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):

☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____

☒ Not Applicable

New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):

☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____

☒ Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):

☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____

☒ Not Applicable (not a CAIR source)

Additional Requirements Comment

EMISSIONS UNIT INFORMATION

Section [1] of [5]

A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

- ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
- ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

- ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).
- ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.
- ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:

One Natural Gas-Fired Combustion Turbine with duct-fired HRSG

3. Emissions Unit Identification Number: **009**

4. Emissions Unit
Status Code:
A

5. Commence
Construction
Date:
**between mid-2019
and early 2020**

6. Initial Startup
Date:
**between late 2021
and early 2022**

7. Emissions Unit
Major Group
SIC Code:
49

8. Federal Program Applicability: (Check all that apply)

- ☒ Acid Rain Unit
- ☐ CAIR Unit

9. Package Unit:

Manufacturer: **General Electric**

Model Number: **7HA.02**

10. Generator Nameplate Rating: **1,183 MW (gross nominal)**

11. Emissions Unit Comment:

One General Electric 7HA.02 combustion turbine with HRSG arranged in a 2-on-1 combined-cycle configuration.

EMISSIONS UNIT INFORMATION

Section [1] of [5]

Emissions Unit Control Equipment/Method: Control 1 of 4

1. Control Equipment/Method Description:
Selective Catalytic Reduction system

2. Control Device or Method Code: **139**

Emissions Unit Control Equipment/Method: Control 2 of 4

1. Control Equipment/Method Description:
Oxidation Catalyst

2. Control Device or Method Code: **109**

Emissions Unit Control Equipment/Method: Control 3 of 4

1. Control Equipment/Method Description:
Dry Low NOx burner

2. Control Device or Method Code: **205**

Emissions Unit Control Equipment/Method: Control 4 of 4

1. Control Equipment/Method Description:
Good Combustion Practices

2. Control Device or Method Code:

EMISSIONS UNIT INFORMATION

Section [1] of [5]

B. EMISSIONS UNIT CAPACITY INFORMATION**(Optional for unregulated emissions units.)****Emissions Unit Operating Capacity and Schedule**

1. Maximum Process or Throughput Rate:
2. Maximum Production Rate:
3. Maximum Heat Input Rate: 3,778.2 MMBtu/hr (HHV) per CT/HRSG
4. Maximum Incineration Rate: pounds/hr tons/day
5. Requested Maximum Operating Schedule: 24 hours/day 52 weeks/year 7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment: Maximum heat input rate based on 25°F ambient temperature and duct burner firing. Requested maximum operating schedule for CT is 8,760 hr/yr per CT. Requested maximum operating schedule for duct burner firing is 8,760 hr/yr per CT.

EMISSIONS UNIT INFORMATION

Section [1] of [5]

C. EMISSION POINT (STACK/VENT) INFORMATION**(Optional for unregulated emissions units.)****Emission Point Description and Type**

1. Identification of Point on Plot Plan or Flow Diagram: 009		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Not applicable			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: Not applicable			
5. Discharge Type Code: V		6. Stack Height: 199 feet	
		7. Exit Diameter: 23.5 feet	
8. Exit Temperature: 240°F		9. Actual Volumetric Flow Rate: 108.3 MMcf/hr	
		10. Water Vapor:	
11. Maximum Dry Standard Flow Rate:		12. Nonstack Emission Point Height:	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: Items 8 and 9 based on 59°F ambient temperature, base load condition, with evaporative cooling and duct burner firing			

EMISSIONS UNIT INFORMATION

Section [1] of [5]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1_ of 1_

1. Segment Description (Process/Fuel Type): Natural gas		
2. Source Classification Code (SCC): 20100201		3. SCC Units: Million Cubic Feet
4. Maximum Hourly Rate: 3.662 MMcf/hr	5. Maximum Annual Rate: 32,079 MMcf/yr	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 1,027
10. Segment Comment: Item 4 based on 25°F ambient temperature with duct burner firing. Item 5 based on 59°F ambient temperature and 8,760 hr/yr CT operation with evaporative cooling and 8,760 hr/yr DB firing per CT.		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

Section [1] of [5]

E. EMISSIONS UNIT POLLUTANTS**List of Pollutants Emitted by Emissions Unit**

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_x	205	139	EL
CO	109		EL
VOC	109		EL
SO₂	Pipeline-quality natural gas		WP
PM	Pipeline-quality natural gas		WP
PM₁₀	Pipeline-quality natural gas		WP
PM_{2.5}	Pipeline-quality natural gas		WP
SAM	Pipeline-quality natural gas		WP
GHG			EL

EMISSIONS UNIT INFORMATION

Section [1] of [5]

POLLUTANT DETAIL INFORMATION

Page [1] of [18]

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: NO_x		2. Total Percent Efficiency of Control: 78%	
3. Potential Emissions: 96.3 lb/hour 420.1 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: See Appendix B Reference:		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Potential emissions in lb/hr based on 25°F ambient temperature with DB firing Potential emissions in tpy based on 59°F ambient temperature, 8,760 hr/yr with 8,760 hr/yr DB firing including startup/shutdown emissions.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [1] of [5]

POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 7 ppmvd @ 15% O₂	4. Equivalent Allowable Emissions: 96.3 lb/hour 420.1 tons/year
5. Method of Compliance: CEMS (24-hour block average)	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart KKKK, Table 1	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 15 ppmvd @ 15% O₂ (Load ≥ 75%)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS (30-operating-day rolling average)	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions are based on the emission unit operating greater than or equal to 75% of the base load.	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart KKKK, Table 1	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 96 ppmvd @ 15% O₂ (Load < 75%)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS (30-operating-day rolling average)	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions are based on the emission unit operating below 75% of the base load.	

EMISSIONS UNIT INFORMATION

Section [1] of [5]

POLLUTANT DETAIL INFORMATION

Page [3] of [18]

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 84.0 lb/hour 386.0 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: See Appendix B Reference:		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Potential emissions in lb/hr based on 25°F ambient temperature with DB firing Potential emissions in tpy based on 59°F ambient temperature, 8,760 hr/yr with 8,760 hr/yr DB firing including startup/shutdown emissions.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [1] of [5]

POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 10 ppmvd @ 15% O2	4. Equivalent Allowable Emissions: 84.0 lb/hour 386.0 tons/year
5. Method of Compliance: Initial stack test and once every 5 years upon Title V permit renewal	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

Section [1] of [5]

POLLUTANT DETAIL INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 9.6 lb/hour 44.9 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: See Appendix B Reference:		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Potential emissions in lb/hr based on 25°F ambient temperature with DB firing Potential emissions in tpy based on 59°F ambient temperature, 8,760 hr/yr with 8,760 hr/yr DB firing including startup/shutdown emissions			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [1] of [5]

POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1_** of **2_**

1. Basis for Allowable Emissions Code: RULE - BACT	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 1.0 ppmvd@ 15% O2	4. Equivalent Allowable Emissions: 4.4 lb/hour 19.3 tons/year
5. Method of Compliance: Initial and annual stack test	
6. Allowable Emissions Comment (Description of Operating Method): Without duct burner-firing	

Allowable Emissions Allowable Emissions **2_** of **2_**

1. Basis for Allowable Emissions Code: RULE - BACT	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2.0 ppmvd@ 15% O2	4. Equivalent Allowable Emissions: 9.6 lb/hour 42.0 tons/year
5. Method of Compliance: Initial and once per permit term stack test	
6. Allowable Emissions Comment (Description of Operating Method): With duct burner-firing	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: SO₂		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 25.3 lb/hour 110.4 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 2.0 gr S/100 scf Reference:		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Potential emissions in lb/hr based on 25°F ambient temperature with DB firing Potential emissions in tpy based on 59°F ambient temperature, 8,760 hr/yr with 8,760 hr/yr DB firing			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions ___ of ___ **Not Applicable**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 26.8 lb/hour 115.3 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: See Appendix B Reference:		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Potential emissions in lb/hr based on 25°F ambient temperature with DB firing Potential emissions in tpy based on 59°F ambient temperature, 8,760 hr/yr with 8,760 hr/yr DB firing			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __ **Not Applicable**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM₁₀		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 26.8 lb/hour 115.3 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: See Appendix B Reference:		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Potential emissions in lb/hr based on 25°F ambient temperature with DB firing Potential emissions in tpy based on 59°F ambient temperature, 8,760 hr/yr with 8,760 hr/yr DB firing			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __ **Not Applicable**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM_{2.5}		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 26.8 lb/hour 115.3 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: See Appendix B Reference:		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:		
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years		
10. Calculation of Emissions: Potential emissions in lb/hr based on 25°F ambient temperature with DB firing Potential emissions in tpy based on 59°F ambient temperature, 8,760 hr/yr with 8,760 hr/yr DB firing			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions ___ of ___ **Not Applicable**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: H₂SO₄ mist		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 16.3 lb/hour 71.0 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 2.0 gr S/100 scf Reference:		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Potential emissions in lb/hr based on 25°F ambient temperature with DB firing Potential emissions in tpy based on 59°F ambient temperature, 8,760 hr/yr with 8,760 hr/yr DB firing			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions ___ of ___ **Not Applicable**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: GHG		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 440,470 lb/hour 1,929,258 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: See below Reference: 40 CFR Part 98, Tables C-1 and C-2 to Subpart C of Part 98		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: 53.06 kg CO2/MMBtu 1.0 E-03 kg CH4/MMBtu 1.0 E-04 kg N2O/MMBtu			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.****Allowable Emissions** Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE - NSPS	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 1,000 lb CO2/MWh gross energy output	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: CO2 CEMS or 40 CFR Part 75, Appendix G	
6. Allowable Emissions Comment (Description of Operating Method): Including periods of startup and shutdown	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: 15 % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: Annual visible emissions test in accordance with EPA Method 9	
5. Visible Emissions Comment: VE during startup/shutdown shall not exceed 15% opacity except for up to one 6-minute averaging period during a 30-minute period, during which VE shall not exceed 20%.	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: 20 % Maximum Period of Excess Opacity Allowed: One 6-minute averaging period during a calendar day	
4. Method of Compliance: EPA Method 9, as required	
5. Visible Emissions Comment: During transient modes of operation such as startup, shutdown, combustor tuning and documented malfunction	

EMISSIONS UNIT INFORMATION

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H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 1

1. Parameter Code: EM	2. Pollutant(s): NO_x
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ____ of ____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

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I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: <u>Section 2.0</u> ☐ Previously Submitted, Date _____
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: <u>Section 2.0</u> ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: <u>Section 2.0</u> ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records: ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute: ☐ Attached, Document ID: _____ ☒ Not Applicable

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Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):	☒ Attached, Document ID: Section 5.0	☐ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):	☐ Attached Document ID: _____	☒ Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)	☐ Attached, Document ID: _____	☒ Not Applicable

1.	Identification of Applicable Requirements:	
	☐ Attached, Document ID: _____	
2.	Compliance Assurance Monitoring:	
	☐ Attached, Document ID: _____	☐ Not Applicable
3.	Alternative Methods of Operation:	
	☐ Attached, Document ID: _____	☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading):	
	☐ Attached, Document ID: _____	☐ Not Applicable

[illegible]

Emissions Unit (EU) 009 (One General Electric 7HA.02 combustion turbine with HRSG arranged in a two-on-one combined-cycle configuration) and EU-010 (one General Electric 7HA.02 combustion turbine with HRSG arranged in a two-on-one combined-cycle configuration) are identical emission units.

The information provided in Section III. Emission Unit Information, Section 1 of 5, for EU-009 is also applicable to Section 2 of 5 for EU-010 with the exception of the identification numbers.

EMISSIONS UNIT INFORMATION

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A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

- ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
- ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

- ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).
- ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.
- ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:

Two 9.99 MMBtu/hr or less natural gas-fired fuel gas heaters

3. Emissions Unit Identification Number: **011**

4. Emissions Unit
Status Code:
C

5. Commence
Construction
Date: between
mid-2019 and early
2020

6. Initial Startup
Date: between
late 2021 and early
2022

7. Emissions Unit
Major Group
SIC Code:
49

8. Federal Program Applicability: (Check all that apply)

- ☐ Acid Rain Unit
- ☐ CAIR Unit

9. Package Unit:
Manufacturer:

Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

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Emissions Unit Control Equipment/Method: Control ___ of ___ **Not Applicable**

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

EMISSIONS UNIT INFORMATION

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B. EMISSIONS UNIT CAPACITY INFORMATION**(Optional for unregulated emissions units.)****Emissions Unit Operating Capacity and Schedule**

1. Maximum Process or Throughput Rate:
2. Maximum Production Rate:
3. Maximum Heat Input Rate: 9.99 MMBtu/hr (HHV)
4. Maximum Incineration Rate: pounds/hr tons/day
5. Requested Maximum Operating Schedule: 24 hours/day 52 weeks/year
7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment:

EMISSIONS UNIT INFORMATION

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C. EMISSION POINT (STACK/VENT) INFORMATION**(Optional for unregulated emissions units.)****Emission Point Description and Type**

1. Identification of Point on Plot Plan or Flow Diagram: 011		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Two natural gas-fired fuel gas heaters			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: Not applicable			
5. Discharge Type Code: V	6. Stack Height: 30 feet	7. Exit Diameter: 2 feet	
8. Exit Temperature: 789 °F	9. Actual Volumetric Flow Rate: 2,192 acfm (per stack)	10. Water Vapor: %	
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:			

EMISSIONS UNIT INFORMATION

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D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): Natural gas		
2. Source Classification Code (SCC): 20100201		3. SCC Units: Million cubic feet burned
4. Maximum Hourly Rate: 9,727 cf/hr	5. Maximum Annual Rate: 85.2 MMcf/yr	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 1,027
10. Segment Comment:		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

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E. EMISSIONS UNIT POLLUTANTS**List of Pollutants Emitted by Emissions Unit**

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_x	Good combustion		WP
CO	Good combustion		WP
VOC	Good combustion		EL

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: NO_x		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.96 lb/hour 8.4 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 100 lb/MMcf Reference: AP-42. Table 1.4-1		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Appendix B for detailed calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions ___ of ___ **Not Applicable**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.81 lb/hour 7.1 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 84 lb/MMcf Reference: AP-42. Table 1.4-1		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Appendix B for detailed calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions ___ of ___ **Not Applicable**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.05 lb/hour 0.5 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 5.5 lb/MMcf Reference: AP-42. Table 1.4-1		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Appendix B for detailed calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions ___ of ___ **Not Applicable**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___ **Not Applicable**

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:	

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:	

EMISSIONS UNIT INFORMATION

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H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of ___ **Not Applicable**

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

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I. EMISSIONS UNIT ADDITIONAL INFORMATION**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: <u>Figure 2-4</u> ☐ Previously Submitted, Date _____
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: <u>Table 2-4</u> ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records: ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute: ☐ Attached, Document ID: _____ ☐ Not Applicable

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Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):	☒ Attached, Document ID: Section 5.0	☐ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):	☐ Attached, Document ID: _____	☒ Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)	☐ Attached, Document ID: _____	☒ Not Applicable

1.	Identification of Applicable Requirements:	
	☐ Attached, Document ID: _____	
2.	Compliance Assurance Monitoring:	
	☐ Attached, Document ID: _____	☐ Not Applicable
3.	Alternative Methods of Operation:	
	☐ Attached, Document ID: _____	☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading):	
	☐ Attached, Document ID: _____	☐ Not Applicable

[illegible]

EMISSIONS UNIT INFORMATION

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A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

- ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
- ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

- ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).
- ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.
- ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:

250 HP Emergency firewater pump engine

3. Emissions Unit Identification Number: **012**

4. Emissions Unit
Status Code:
C

5. Commence
Construction
Date: between
mid-2019 and early
2020

6. Initial Startup
Date: between
late 2021 and early
2022

7. Emissions Unit
Major Group
SIC Code:
49

8. Federal Program Applicability: (Check all that apply)

- ☐ Acid Rain Unit
- ☐ CAIR Unit

9. Package Unit:
Manufacturer:

Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

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Emissions Unit Control Equipment/Method: Control ___ of ___ **Not Applicable**

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

EMISSIONS UNIT INFORMATION

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B. EMISSIONS UNIT CAPACITY INFORMATION**(Optional for unregulated emissions units.)****Emissions Unit Operating Capacity and Schedule**

1. Maximum Process or Throughput Rate:
2. Maximum Production Rate:
3. Maximum Heat Input Rate:
4. Maximum Incineration Rate: pounds/hr tons/day
5. Requested Maximum Operating Schedule: 24 hours/day 7 days/week 52 weeks/year 500 hours/year
6. Operating Capacity/Schedule Comment: Fire water pump will be operated for emergency purposes only. Maintenance and testing will not exceed 100 hours per year. There are no restrictions on hours of operation during emergency events. Potential emissions are based on 500 hours per year in accordance with EPA guidance.

EMISSIONS UNIT INFORMATION

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C. EMISSION POINT (STACK/VENT) INFORMATION**(Optional for unregulated emissions units.)****Emission Point Description and Type**

1. Identification of Point on Plot Plan or Flow Diagram: 012		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Not applicable			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: Not applicable			
5. Discharge Type Code: V	6. Stack Height: TBD	7. Exit Diameter: 0.5 ft	
8. Exit Temperature: 961 °F	9. Actual Volumetric Flow Rate: TBD acfm	10. Water Vapor: %	
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:			

EMISSIONS UNIT INFORMATION

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D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1_ of 1_

1. Segment Description (Process/Fuel Type): Ultra-low sulfur diesel (ULSD) fuel		
2. Source Classification Code (SCC): 20100102		3. SCC Units: 1,000 gallons
4. Maximum Hourly Rate: .0146	5. Maximum Annual Rate: 7.3	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash:	9. Million Btu per SCC Unit: 140
10. Segment Comment:		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

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E. EMISSIONS UNIT POLLUTANTS**List of Pollutants Emitted by Emissions Unit**

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_x			EL
CO			EL
PM			EL
VOC			EL

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: NO_x		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 1.7 lb/hour 0.3 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 3.0 g/hp-hr (NO_x + NMHC) Assume 70% NO_x and 30% NMHC Reference: NSPS, Subpart III			7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Annual potential emissions based on 500 hr/yr			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 3.0 g/hp-hr (NO_x + NMHC)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer's certificate of conformity	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 1.4 lb/hour 0.4 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 2.6 g/hp-hr Reference: NSPS, Subpart IIII		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Annual potential emissions based on 500 hr/yr			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.****Allowable Emissions** Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2.6 g/hp-hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer's certificate of conformity	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.1 lb/hour 0.02 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 0.15 g/hp-hr Reference: NSPS, Subpart IIII		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Annual potential emissions based on 500 hr/yr			
11. Potential, Fugitive, and Actual Emissions Comment:			

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.****Allowable Emissions** Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.15 g/hp-hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer's certificate of conformity	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.5 lb/hour 0.1 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 3.0 g/hp-hr (NO_x+NMHC) Assume 70% NO_x and 30% NMHC Reference: NSPS, Subpart IIII		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Annual potential emissions based on 500 hr/yr			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.****Allowable Emissions** Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 3.0 g/hp-hr (NO_x+NMHC)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer's certificate of conformity	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___ **Not Applicable**

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:	

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:	

EMISSIONS UNIT INFORMATION

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H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ____ of ____ **Not Applicable**

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ____ of ____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

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I. EMISSIONS UNIT ADDITIONAL INFORMATION**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Table 2-5 ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records: ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute: ☐ Attached, Document ID: _____ ☒ Not Applicable

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Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):	☒ Attached, Document ID: Section 5.0	☐ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):	☐ Attached, Document ID: _____	☒ Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)	☐ Attached, Document ID: _____	☒ Not Applicable

1.	Identification of Applicable Requirements:	
	☐ Attached, Document ID: _____	
2.	Compliance Assurance Monitoring:	
	☐ Attached, Document ID: _____	☐ Not Applicable
3.	Alternative Methods of Operation:	
	☐ Attached, Document ID: _____	☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading):	
	☐ Attached, Document ID: _____	☐ Not Applicable

[illegible]

EMISSIONS UNIT INFORMATION

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A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)
- ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
- ☒ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)
- ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).
- ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.
- ☒ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:

16-Cell Wet Mechanical Draft Cooling Tower

3. Emissions Unit Identification Number: **013**

4. Emissions Unit
Status Code:
C

5. Commence
Construction
Date:

6. Initial Startup
Date:

7. Emissions Unit
Major Group
SIC Code:
49

8. Federal Program Applicability: (Check all that apply)

☐ Acid Rain Unit

☐ CAIR Unit

9. Package Unit:

Manufacturer:

Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

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Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: Mist eliminator – high velocity

2. Control Device or Method Code: 014

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:

2. Control Device or Method Code:

EMISSIONS UNIT INFORMATION

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B. EMISSIONS UNIT CAPACITY INFORMATION**(Optional for unregulated emissions units.)****Emissions Unit Operating Capacity and Schedule**

1. Maximum Process or Throughput Rate:
2. Maximum Production Rate:
3. Maximum Heat Input Rate:
4. Maximum Incineration Rate: pounds/hr tons/day
5. Requested Maximum Operating Schedule: 24 hours/day 52 weeks/year
7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment:

EMISSIONS UNIT INFORMATION

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C. EMISSION POINT (STACK/VENT) INFORMATION**(Optional for unregulated emissions units.)****Emission Point Description and Type**

1. Identification of Point on Plot Plan or Flow Diagram: 013		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Not applicable			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: Not applicable			
5. Discharge Type Code: V	6. Stack Height: 56 ft	7. Exit Diameter: 36 ft	
8. Exit Temperature: 91°F	9. Actual Volumetric Flow Rate: 28,824 acfm	10. Water Vapor: %	
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:			

EMISSIONS UNIT INFORMATION

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D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment __ of __ **Not Applicable**

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

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E. EMISSIONS UNIT POLLUTANTS**List of Pollutants Emitted by Emissions Unit**

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	014	N/A	NS
PM₁₀	014	N/A	NS
PM_{2.5}	014	N/A	NS

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

Page [1] of [6]

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.38 lb/hour 1.7 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 0.0005% Drift Loss Rate Reference:		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions:			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.****Allowable Emissions** Allowable Emissions ___ of ___ **Not Applicable**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION**POLLUTANT DETAIL INFORMATION**

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM₁₀		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.1 lb/hour 0.2 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 0.0005% Drift Loss Rate Reference:		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions:			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions ___ of ___ **Not Applicable**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –**POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM_{2.5}	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.1 lb/hour 0.2 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 0.0005% Drift Loss Rate Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions:	
11. Potential, Fugitive, and Actual Emissions Comment:	

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -**ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions ___ of ___ **Not Applicable**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___ **Not Applicable**

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:	

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:	

EMISSIONS UNIT INFORMATION

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H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of ___ **Not Applicable**

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

Section [5] of [5]

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: <u>Figure 2-4</u> ☐ Previously Submitted, Date _____
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: <u>Section 5.0</u> ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records: ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute: ☐ Attached, Document ID: _____ ☒ Not Applicable

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Additional Requirements for Air Construction Permit Applications

Additional Requirements for Title V Air Operation Permit Applications

Additional Requirements Comment

[illegible]

Appendix B

SCCF Potential Emissions Rate Calculations

Seminole Combined-Cycle Generating Station

Table B-1. Seminole Combined-Cycle Generating Station

Operating Scenarios - 2-on-1 7HA.02 CT/HRSG Unit Operating in Combined-Cycle Mode

Case	GE Case	Ambient Temperature (°F)	CT/HRSG 1A and 1B			Annual Profile #1 (hr/yr)	Annual Profile #2 (hr/yr)	Annual Profile #3 (hr/yr)	Inlet Air Evaporative Cooling	Duct Burner Firing
			Load							
			100 %	70 % *	MECL*					
		Winter								
1	50	25	✓ ✓							
2	49	25	✓ ✓				2,000	2,000		✓
3	51	25		✓						
4	53	25			✓					
		Annual Average								
5	36	59	✓ ✓							
6	34	59	✓ ✓						✓	
7	37	59	✓ ✓							✓
8	35	59	✓ ✓			8,760	4,760	4,393	✓	✓
9	39	59		✓						
10	41	59			✓					
		Summer								
11	10	95	✓ ✓						✓	
12	8	95	✓ ✓				2,000	2,000	✓	✓
13	12	95		✓						
14	14	95			✓					
		Startups	Events							
		Cold	10					20		
		Warm	50					79		
		Hot	200					217		
		Shutdowns	260					52		

* At low operating loads CT/HRSG units can be operated interchangeably.

Note: ✓ = number of CTs.

Sources: GE Combined Cycle Systems Emissions Data, 08-Sept-2017, Rev. I.
SECI, 2017.
ECT, 2017.

Table B-2. Seminole Generating Station - GE 207HA.02 CTs (Combined-cycle Mode)

CTG/HRSG Hourly Emission Rates (Per CTG/HRSG)

Criteria and Selected Non-Criteria Air Pollutants

Temp. (°F)	Case	Load (%)	PM ₁₀ /PM _{2.5} ¹		SO ₂ ²		H ₂ SO ₄ ³		Lead ⁴	
			(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)
25	1	Base	22.7	2.86	23.40	2.95	15.00	1.890	0.0018	0.00022
	2	Base + DB	26.8	3.38	25.32	3.19	16.30	2.054	0.0019	0.00024
	3	70	19.8	2.49	17.76	2.24	11.40	1.436	0.0013	0.00017
	4	MECL	16.0	2.02	10.43	1.31	6.70	0.844	0.0008	0.00010
59	5	Base	22.8	2.87	23.52	2.96	15.10	1.903	0.0018	0.00022
	6	Base + EV	22.8	2.87	23.52	2.96	15.10	1.903	0.0018	0.00022
	7	Base + DB	26.2	3.30	25.20	3.18	16.20	2.041	0.0019	0.00024
	8	Base + DB + EV	26.3	3.31	25.20	3.18	16.20	2.041	0.0019	0.00024
	9	70	19.7	2.48	17.52	2.21	11.30	1.424	0.0013	0.00017
	10	MECL	15.6	1.97	9.56	1.20	6.14	0.774	0.0007	0.00009
95	11	Base + EV	22.5	2.84	22.80	2.87	14.70	1.852	0.0017	0.00022
	12	Base + DB + EV	25.9	3.26	24.48	3.08	15.80	1.991	0.0018	0.00023
	13	70	19.1	2.41	16.44	2.07	10.60	1.336	0.0012	0.00016
	14	MECL	16.3	2.05	10.98	1.38	7.05	0.888	0.0008	0.00010
Maximums			26.8	3.38	25.32	3.19	16.30	2.054	0.0019	0.00024

Temp. (°F)	Case	Load (%)	NO _x			CO			VOC ⁶		
			(ppmvd) ⁵	(lb/hr)	(g/sec)	(ppmvd) ⁵	(lb/hr)	(g/sec)	(ppmvd) ⁵	(lb/hr)	(g/sec)
25	1		7.0	88.6	11.16	10.0	77.0	9.70	1.0	4.4	0.56
	2	Base + DB	7.0	96.3	12.13	10.0	84.0	10.58	2.0	9.6	1.21
	3	70	7.0	67.6	8.51	10.0	58.5	7.37	1.0	3.4	0.42
	4	MECL	7.0	39.6	4.98	10.0	34.4	4.33	1.0	2.0	0.25
59	5	Base	7.0	89.3	11.25	10.0	77.5	9.77	1.0	4.4	0.56
	6	Base + EV	7.0	89.3	11.25	10.0	77.5	9.77	1.0	4.4	0.56
	7	Base + DB	7.0	95.6	12.04	10.0	83.0	10.46	2.0	9.5	1.20
	8	Base + DB + EV	7.0	95.9	12.08	10.0	83.5	10.52	2.0	9.5	1.20
	9	70	7.0	66.5	8.38	10.0	58.0	7.31	1.0	3.3	0.42
	10	MECL	7.0	36.4	4.59	10.0	31.5	3.97	1.0	1.8	0.23
95	11	Base + EV	7.0	86.8	10.94	10.0	75.5	9.51	1.0	4.3	0.54
	12	Base + DB + EV	7.0	93.1	11.73	10.0	81.0	10.21	2.0	9.3	1.17
	13	70	7.0	62.3	7.85	10.0	54.0	6.80	1.0	3.1	0.39
	14	MECL	7.0	41.7	5.25	10.0	36.2	4.56	1.0	2.1	0.26
Maximums			7.0	96.3	12.13	10.0	84.0	10.58	2.0	9.6	1.21

¹ Filterable and condensable PM assumes all SO₃ converts to (NH₄)₂SO₃ generated in the SCR.

² Based on a natural gas sulfur content of 2.0 gr/100 scf; assumes all sulfur in the natural gas converts to SO₂.

³ Based on 5% conversion of fuel sulfur to SO₃, 30% conversion of SO₂ to SO₃ in the oxidation catalyst, and 5% conversion of SO₂ to SO₃ in the SCR.

⁴ Natural Gas Combustion, Table 1.4-2, AP-42, 3/98;

⁵ at 15% O₂;

⁶ Non-methane hydrocarbons (NMHC) expressed as methane.

Source: GE, 2017.

Table B-3. Seminole Generating Station - GE 207HA.02 CTs (Combined-cycle Mode)
CT/HRSG Emission Rates For Two CT/HRSG Units Operating in CC Mode - Annual Profile 1
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	Annual Operations (hrs/yr)	Emission Rates							
			NO _x		CO		VOC		NH ₃	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT/HRSG 1A/1B	8	8,760	191.8	840.1	167.0	731.5	19.1	83.5	50.2	219.7
	Totals	8,760	N/A	840.1	N/A	731.5	N/A	83.5	N/A	219.7

Source	Case	Annual Operations (hrs/yr)	Emission Rates							
			PM/PM ₁₀		SO ₂ *		H ₂ SO ₄ *		Lead	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT/HRSG 1A/1B	8	8,760	52.6	230.4	50.4	220.8	32.40	141.9	0.004	0.017
	Totals	8,760	N/A	230.4	N/A	220.8	N/A	141.9	N/A	0.0

*PM/PM₁₀, SO₂ and H₂SO₄ emission rates based on a natural gas sulfur content limit of 2.0 grains/100 scf.

Source: Seminole, GE, ECT; 2017.

Table B-4. Seminole Generating Station - GE 207HA.02 CTs (Combined-cycle Mode)
CT/HRSG Emission Rates For Two CT/HRSG Units Operating in CC Mode - Annual Profile 2
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	Annual Operations (hrs/yr)	Emission Rates							
			NO _x		CO		VOC		NH ₃	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT/HRSG 1A/1B	2	2,000	192.5	192.5	168.0	168.0	19.2	19.2	50.7	50.7
CT/HRSG 1A/1B	8	4,760	191.8	456.5	167.0	397.5	19.1	45.4	50.2	119.4
CT/HRSG 1A/1B	12	2,000	186.2	186.2	162.0	162.0	18.5	18.5	48.7	48.7
	Totals	8,760	N/A	835.2	N/A	727.5	N/A	83.0	N/A	218.8

Source	Case	Annual Operations (hrs/yr)	Emission Rates							
			PM/PM ₁₀		SO ₂ *		H ₂ SO ₄ *		Lead	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT/HRSG 1A/1B	2	2,000								
CT/HRSG 1A/1B	2	2,000	53.6	53.6	50.6	50.6	32.60	32.6	0.004	0.004
CT/HRSG 1A/1B	8	4,760	52.6	125.2	50.4	120.0	32.40	77.1	0.004	0.009
CT/HRSG 1A/1B	12	2,000	51.8	51.8	49.0	49.0	31.60	31.6	0.004	0.004
	Totals	8,760	N/A	230.6	N/A	219.6	N/A	141.3	N/A	0.0

*PM/PM₁₀, SO₂ and H₂SO₄ emission rates based on annual natural gas sulfur content limit of 2.0 grains/100 scf.

Source: Seminole, GE, ECT; 2017.

Table B-5. Seminole Generating Station - GE 207HA.02 CTs (Combined-cycle Mode)
CT/HRSG Emission Rates For Two CT/HRSG Units Operating in CC Mode - Annual Profile 3
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	Annual Operations (hrs/yr)			Emission Rates							
					NO _x		CO		VOC		NH ₃	
					(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT/HRSG 1A/1B	2	2,000			192.5	192.5	168.0	168.0	19.2	19.2	50.7	50.7
CT/HRSG 1A/1B	8	4,393			191.8	421.3	167.0	366.8	19.1	41.9	50.2	110.2
CT/HRSG 1A/1B	12	2,000			186.2	186.2	162.0	162.0	18.5	18.5	48.7	48.7
Subtotal - Normal Operations						800.0		696.8		79.5		209.6
		(events/yr)	(min./event)	(hours/yr)	(lb/event)†	(tpy)	(lb/event)†	(tpy)	(lb/event)†	(tpy)	(lb/event)†	(tpy)
Startups ^{2,3}	Cold	10	117	20	842.0	4.2	1808.0	9.0	134.0	0.7		
	Warm	50	95	79	476.0	11.9	332.0	8.3	24.0	0.6		
	Hot	200	65	217	204.0	20.4	256.0	25.6	21.0	2.1		
Shutdowns		260	12	52	14.0	1.8	248.0	32.2	52.0	6.8		
Downtime												
Subtotal - Startups/Shutdowns						38.3		75.2		10.1		
	Totals	8,760			N/A	838.3	N/A	772.0	N/A	89.7	N/A	209.6

Source	Case	Annual Operations (hrs/yr)			Emission Rates							
					PM/PM ₁₀		SO ₂ ¹		H ₂ SO ₄ ¹		Lead	
					(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT/HRSG 1A/1B	2	2,000										
CT/HRSG 1A/1B	8	4,393			53.6	53.6	50.6	50.6	32.60	32.6	0.004	0.004
CT/HRSG 1A/1B	12	2,000			52.6	115.5	50.4	110.7	32.40	71.2	0.004	0.008
CT/HRSG 1A/1B	12	2,000			51.8	51.8	49.0	49.0	31.60	31.6	0.004	0.004
Subtotal - Normal Operations						220.9		210.3		135.4		0.0
		(events/yr)	(min./event)	(hours/yr)	(lb/event)†	(tpy)	(lb/event)†	(tpy)	(lb/event)†	(tpy)	(lb/event)†	(tpy)
Startups ^{2,3}	Cold	10	117	20	76.0	0.4	0.2	0.0				
	Warm	50	95	79	63.0	1.6	0.06	0.0				
	Hot	200	65	217	40.0	4.0	0.06	0.0				
Shutdowns		260	12	52	8.8	1.1	0.05	0.0				
Downtime												
Subtotal - Startups/Shutdowns						7.1		0.0				
	Totals	8,760			N/A	228.0	N/A	210.3	N/A	135.4	N/A	0.016

1. PM/PM₁₀, SO₂ and H₂SO₄ emission rates based on annual natural gas sulfur content limit of 2.0 grains/100 scf.

2. Startup hours based on

10 cold starts at 117 minutes per startup.

50 number of warm starts at 95 minutes per startup.

200 number of hot starts at 65 minutes per startup.

260 number of shutdowns at 12 minutes per shutdown.

3. Average number of start-ups for two combustion turbines.

†Values provided for 2x1 7HA.02 Plant Start.

Source: Seminole, GE, ECT; 2017.

Table B-6. Seminole Generating Station - SCCF Project
Summary of Facility Annual Pollutant Emission Rates

Criteria Pollutant	CT/HRSG Units (2) (tpy)	Cooling Tower (tpy) (8,760 hr/yr)	Fire Water Pump IC Engine (tpy) (500 hr/yr)	Fuel Gas Heaters (tpy) (8,760 hr/yr)	Natural Gas Piping (tpy)	Circuit Breakers (tpy)	Totals (tpy)
NO _x	840.1	N/A	0.29	8.41	N/A	N/A	848.8
CO	772.0	N/A	0.36	7.07	N/A	N/A	779.4
VOC	89.7	N/A	0.12	0.46	N/A	N/A	90.3
SO ₂	220.8	N/A	0.00	0.50	N/A	N/A	221.3
PM	230.6	1.7	0.02	0.64	N/A	N/A	232.9
PM ₁₀ /PM _{2.5}	230.6	0.2	0.02	0.64	N/A	N/A	231.5
Pb	1.66E-02	N/A	Negligible	0.0	N/A	N/A	0.017
H ₂ SO ₄ Mist	141.9	N/A	Negligible		N/A	N/A	141.9
GHG (as CO ₂ e)	3,858,516	N/A	82	10,249	24	120	3,868,991
Formaldehyde*	9.4	N/A	5.90E-04	6.31E-03	N/A	N/A	9.4
Total HAP	19.2	N/A	0.003	0.159	N/A	N/A	19.3

N/A - not applicable

Source: ECT, 2017.

Table B-7. Seminole Generating Station - GE 207HA.02 CTs (Combined-cycle Mode)

A. Natural Gas Fuel Flow Rates; Per CT/HRSG Unit

Case	25 deg F				59 deg F						95 deg F			
	Base 1	Base 2	70% load 3	MECL 4	Base 5	Base 6	Base 7	Base 8	70% load 9	MECL 10	Base 11	Base 12	70% load 13	MECL 14
Heat Input - HHV (MMBtu/hr)	3,492.7	3,778.2	2,657.5	1,559.2	3,514.0	3,515.6	3,753.6	3,760.9	2,619.5	1,429.3	3,415.0	3,653.5	2,455.1	1,640.8
Fuel Rate* (lb/hr)	152,215	164,657	115,813	67,952	153,144	153,212	163,585	163,902	114,159	62,292	148,829	159,220	106,995	71,507
Fuel Rate (lb/sec)	42.282	45.738	32.170	18.875	42.540	42.559	45.440	45.528	31.711	17.303	41.341	44.228	29.721	19.863
Fuel Rate** (10 ⁶ ft ³ /hr)	3.515	3.803	2.675	1.569	3.537	3.538	3.778	3.785	2.636	1.439	3.437	3.677	2.471	1.651

B. Natural Gas Fuel Flow Rates; Per Duct Burner

	Rated Heat Input (%)		
	100	70	50
Heat Input - HHV (MMBtu/hr)	285.0	199.5	142.5
Fuel Rate* (lb/hr)	12,420	8,694	6,210.2
Fuel Rate (lb/sec)	3.450	2.4	1.725
Fuel Rate** (10 ⁶ ft ³ /hr)	0.287	0.2	0.143

* Based on natural gas heat content of 22946 Btu/lb (HHV)

** Based on natural gas density of 0.0453222 lb/ft³.

Sources: GE, 2017.
SECI, 2017.
ECT, 2017.

Table B-8. Seminole Generating Station - GE 207HA.02 CTs
Potential Greenhouse Gas (GHG) Emissions

Potential Carbon Dioxide Equivalent (CO ₂ e) Emissions											
Emission Source	Maximum Annual Potential Heat Input	CO ₂			CH ₄			N ₂ O			CO ₂ e Potential Emissions
		Emission Factor ¹	Potential CO ₂ Emissions	Potential CO ₂ e Emissions ³	Emission Factor ²	Potential CH ₄ Emissions	Potential CO ₂ e Emissions ³	Emission Factor ²	Potential N ₂ O Emissions	Potential CO ₂ e Emissions ³	
	(MMBtu/yr)	(kg/MMBtu)	(short tons/yr)	(short tons/yr)	(kg/MMBtu)	(short tons/yr)	(short tons/yr)	(kg/MMBtu)	(short tons/yr)	(short tons/yr)	(short tons/yr)
CT/HRSG (Per CT)	32,945,502										
CT/HRSG (2 CTs)	65,891,003	53.06	3,854,535	3,854,535	1.0E-03	73	1816	1.0E-04	7	2165	3,858,516
Fuel Gas Heaters	175,025	53.06	10,239	10,239	1.0E-03	0	5	1.0E-04	0	6	10,249
Emergency Fire Water Pump	1,000	73.96	82	82	3.0E-03	0	0	6.0E-04	0	0	82
Total CO ₂ e Potential Annual Emissions											3,868,847

Potential CO ₂ e Emissions from Natural Gas Piping Components					
Component	Number of Components	Emission Factor (scf/hr/ component) ⁴	Annual CO ₂ Emissions (tpy)	Annual CH ₄ Emissions (tpy)	Annual CO ₂ e Emissions ³ (tpy)
Valve	168	0.027	0.02	0.81	20.3
Flange	64	0.003	0.00	0.03	0.9
Relief Valves	18	0.040	0.00	0.13	3.2
Total					24.3

Potential CO ₂ e Emissions from Circuit Breakers							
Component	Number of Circuit Breakers	Quantity of SF ₆ insulating gas per component (lb)	Total Quantity of SF ₆ insulating gas (lb)	Annual Leak rate ⁵ (%)	Annual SF ₆ Emissions (lb/yr)	Annual SF ₆ Emissions (tpy)	Annual CO ₂ e Emissions ³ (tpy)
Circuit Breaker	7	300	2,100	0.50	10.5	0.00525	119.7
Total							119.7

Total Facility Potential CO ₂ e Emissions		
	Annual CO ₂ e Emissions (tpy)	% Contribution
Fuel Combustion Sources	3,868,847	99.9963%
NG Piping Components	24	0.0006%
Circuit Breakers	120	0.0031%
Total	3,868,991	

Source: ECT, 2017.

1. Mandatory Reporting of Greenhouse Gases, Final Rule; Federal Register Vol. 74, No. 209, October 30, 2009, Table C-1 To Subpart C of Part 98

2. Mandatory Reporting of Greenhouse Gases, Final Rule; Federal Register Vol. 74, No. 209, October 30, 2009, Table C-2 To Subpart C of Part 98

3. Based on Global Warming Potential of 1 for CO₂, 25 for CH₄, 298 for N₂O and 22,800 for SF₆

4. Mandatory Reporting of Greenhouse Gases, Final Rule; Federal Register Vol. 74, No. 209, October 30, 2009, Table W-1A To Subpart W of Part 98

5. Industry standard estimated leak rate

**Table B-9. Seminole Generating Station - GE 207HA CTs (Two CT/HRSG Units in Combined-cycle Mode)
NG-Firing: Maximum CT & Duct Burner HAP Emissions**

Parameter	Units	Combustion Turbine		Duct Burner
		100%, 25 °F	100%, 59 °F	100%
Maximum Heat Input (HHV):	MMBtu/hr	3,493	3,514	248
Maximum Annual Hours:	hrs/yr	8,760	8,760	8,760

Pollutant	CT Emission Factor ¹ (lb/MMBtu)	DB Emission Factor ^{3,4} (lb/MMBtu)	Maximum CT (lb/hr)	Maximum DB (lb/hr)	CT & DB Total ⁵ (lb/hr)	2 CTs & DBs Total ⁶ TPY
1,3-Butadiene	4.3E-07	N/A	1.50E-03	N/A	1.50E-03	1.32E-02
Acetaldehyde	4.0E-05	N/A	1.40E-01	N/A	1.40E-01	1.23E+00
Acrolein	6.4E-06	N/A	2.24E-02	N/A	2.24E-02	1.97E-01
Benzene	1.2E-05	2.1E-06	4.19E-02	5.10E-04	4.24E-02	3.74E-01
Ethylbenzene	3.2E-05	N/A	1.12E-01	N/A	1.12E-01	9.85E-01
Formaldehyde ²	3.0E-04	7.4E-05	1.05E+00	1.82E-02	1.07E+00	9.39E+00
Naphthalene	1.3E-06	6.0E-07	4.54E-03	1.48E-04	4.69E-03	4.13E-02
Polycyclic Aromatic Hydrocarbons (PAHs)	2.2E-06	N/A	7.68E-03	N/A	7.68E-03	6.77E-02
Propylene Oxide	2.9E-05	N/A	1.01E-01	N/A	1.01E-01	8.93E-01
Toluene	1.3E-04	3.3E-06	4.54E-01	8.26E-04	4.55E-01	4.01E+00
Xylene	6.4E-05	N/A	2.24E-01	N/A	2.24E-01	1.97E+00
Max. individual HAP						9.4
Total HAPs						19.2

¹ - EPA AP-42, Table 3.1-3, April 2000.

² - CT Factor is based on the average of EPA AP-42 test data for large, heavy duty CTs.

³ - EPA AP-42, Table 1.4-3, March 1998.

⁴ - EPA AP-42, Table 1.4-4, March 1998.

⁵ - Based on baseload and 25°F ambient temperature.

⁶ - Based on baseload and 59°F ambient temperature.

Source: ECT, 2017.

Table B-10. Seminole Generating Station - GE 207HA.02 CTs (Combined-cycle Mode)
CTG/HRSG Exhaust Flow Rates (per CTG/HRSG)

A. Exhaust Molecular Weight (MW)

		Exhaust Gas Composition - Volume %													
Component	MW (lb/mole)	25 deg F				59 deg F						95 deg F			
		Base	Base	70% load	MECL	Base	Base	Base	Base	70% load	MECL	Base	Base	70% load	MECL
Case		1	2	3	4	5	6	7	8	9	10	11	12	13	14
Evap. Cooling Duct Burners		N	N	N	N	N	Y	N	Y	N	N	Y	Y	N	N
Ar	39.944	0.90	0.90	0.89	0.89	0.88	0.88	0.88	0.88	0.88	0.89	0.86	0.86	0.86	0.87
N ₂	28.013	74.52	74.26	74.55	75.04	73.97	73.79	73.77	73.59	74.06	74.55	72.02	71.84	72.44	72.79
O ₂	31.999	11.43	10.69	11.54	12.89	11.24	11.15	10.68	10.57	11.48	12.88	10.85	10.32	11.38	12.39
CO ₂	44.010	4.39	4.73	4.35	3.72	4.42	4.44	4.68	4.71	4.31	3.66	4.35	4.59	4.14	3.67
H ₂ O	18.015	8.76	9.43	8.67	7.46	9.49	9.74	9.99	10.26	9.27	8.02	11.92	12.39	11.18	10.28
SO ₂	64.063	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH ₄)	16.043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Exhaust MW (lb/mole)		28.40	28.36	28.41	28.48	28.32	28.30	28.29	28.27	28.34	28.42	28.05	28.02	28.11	28.17
Exhaust Flow (lb/sec)		1,679.4	1,682.9	1,282.2	894.7	1,674.8	1,667.3	1,677.4	1,670.0	1,277.8	887.5	1,643.1	1,645.6	1,230.2	923.2
Exhaust Temperature (°F)		245	240	228	201	248	249	240	240	230	200	250	243	230	211
(K)		391	389	382	367	393	394	389	389	383	366	394	390	383	373
Exhaust O ₂ (Vol %, Dry)		12.53	11.80	12.64	13.93	12.42	12.35	11.86	11.78	12.65	14.00	12.32	11.78	12.81	13.81

B. Exhaust Flow Rates

	Flow Rates (ft ³ /min)													
	25 deg F				59 deg F						95 deg F			
	Base	Base	70% load	MECL	Base	Base	Base	Base	70% load	MECL	Base	Base	70% load	MECL
Case	1	2	3	4	5	6	7	8	9	10	11	12	13	14
ACFM ¹	1,837,825	1,831,295	1,369,022	915,407	1,845,595	1,841,575	1,829,644	1,823,251	1,371,680	908,806	1,833,486	1,820,018	1,331,149	969,515
Velocity (fps) ²	70.6	70.4	52.6	35.2	70.9	70.8	70.3	70.1	52.7	34.9	70.5	69.9	51.2	37.3
Velocity (m/s) ²	21.5	21.4	16.0	10.7	21.6	21.6	21.4	21.4	16.1	10.6	21.5	21.3	15.6	11.4
SCFM, Dry ³	1,247,194	1,242,506	952,948	672,011	1,237,182	1,229,341	1,233,648	1,225,710	945,776	664,132	1,192,698	1,189,402	898,519	679,759
ACFM (15% O ₂ , Dry)	2,379,566	2,558,901	1,751,413	1,000,875	2,401,335	2,407,888	2,522,099	2,529,526	1,739,609	977,170	2,348,951	2,464,551	1,621,012	1,045,347
SCFM (15% O ₂ , Dry)	1,769,874	1,916,855	1,334,854	793,985	1,778,497	1,780,835	1,889,286	1,894,850	1,322,015	776,355	1,734,800	1,838,300	1,231,887	816,906

¹ Based on an site elevation of 195 ft amsl.

² Based on a stack diameter of 20 ft.

³ At 68 °F.

Sources: GE, 2017.
ECT, 2017.

Table B-11

POTENTIAL EMISSION INVENTORY WORKSHEET				
Seminole Generating Station				CTWR1 - 10
EMISSION SOURCE TYPE				
COOLING TOWERS - PM/PM ₁₀				
FACILITY AND SOURCE DESCRIPTION				
Emission Source Description:		Mechanical Draft Cooling Towers		
Emission Control Method(s)/ID No.(s):		Drift Mist Eliminators		
Emission Point Description:		Sixteen-cell Cooling Tower		
EMISSION ESTIMATION EQUATIONS				
PM Emission (lb/hr) = Recirculating Water Flow Rate (gpm) x (Drift Loss Rate (%) / 100) x 8.345 lb/gal x (TDS (ppmw) / 100) x 60 min/hr				
PM Emission (ton/yr) = PM Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)				
PM ₁₀ Emission (lb/hr) = PM Emissions (lb/hr) x PM ₁₀ /PM Fraction				
PM ₁₀ Emission (ton/yr) = PM ₁₀ Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)				
Source: ECT, 2017.				
INPUT DATA AND EMISSIONS CALCULATIONS				
Cooling Tower Data (Per Tower)				
Operating Hours:	8,760	hrs/yr	Estimated maximum TDS in recirculation water. Based on PM/PM ₁₀ testing on cooling towers.	
Number of Cells per Tower:	16			
Recirculating Water Flow Rate:	232,835	gal/min		
Drift Loss Rate:	0.00050	%		
Total Dissolved Solids (TDS):	654	ppmw		
PM ₁₀ /PM Fraction:	0.132			
Number of Towers:	1			
Pollutant	Potential Emission Rates (Per Cell)		Potential Emission Rates (One Tower)	
	(lb/hr)	(g/s)	(lb/hr)	(tpy)
PM	0.024	0.0030	0.4	1.7
PM ₁₀	0.003	0.0004	0.1	0.2
SOURCES OF INPUT DATA				
Parameter	Data Source			
Operating Hours (annual)	Seminole, 2017			
Recirculating Water Flow Rate (gpm)	Seminole, 2017			
Drift Loss Rate (%)	Seminole, 2017			
PM ₁₀ /PM Fraction:	ECT, 2017			
TDS (ppmw)	Seminole, 2017			
NOTES AND OBSERVATIONS				
DATA CONTROL				
Data Collected by:	W. Karl			Oct-17
Data Entered by:	W. Karl			Oct-17
Reviewed by:	A. Taggart			Oct-17

Table B-12. Seminole Generating Station
Cooling Tower PM₁₀ Fraction - Cooling Towers

Procedure Citation:

AWMA Abstract No. 216, Session No. AM-1b, Orlando, 2001.
Calculating Realistic PM₁₀ Emissions from Cooling Towers

Cooling Tower Design Data:

Cooling Tower Recirculating Water Total Dissolved Solids:	654	ppmw
Cooling Tower PM ₁₀ Density (assumed NaCl):	2.2	g/cm ³

Particle Size Distribution:

Droplet Diameter (μm)	Droplet Volume (m ³)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m ³)	Particle Diameter (μm)	Mass Fraction (%)
10	5.24E-16	5.24E-10	3.42E-13	1.56E-19	0.667	0.000
20	4.19E-15	4.19E-09	2.74E-12	1.25E-18	1.335	0.196
30	1.41E-14	1.41E-08	9.25E-12	4.20E-18	2.002	0.226
40	3.35E-14	3.35E-08	2.19E-11	9.96E-18	2.670	0.514
50	6.54E-14	6.54E-08	4.28E-11	1.95E-17	3.337	1.816
60	1.13E-13	1.13E-07	7.40E-11	3.36E-17	4.004	5.702
70	1.80E-13	1.80E-07	1.17E-10	5.34E-17	4.672	21.348
90	3.82E-13	3.82E-07	2.50E-10	1.13E-16	6.007	49.812
110	6.97E-13	6.97E-07	4.56E-10	2.07E-16	7.341	70.509
130	1.15E-12	1.15E-06	7.52E-10	3.42E-16	8.676	82.023
150	1.77E-12	1.77E-06	1.16E-09	5.25E-16	10.011	88.012
180	3.05E-12	3.05E-06	2.00E-09	9.08E-16	12.013	91.032
210	4.85E-12	4.85E-06	3.17E-09	1.44E-15	14.015	92.468
240	7.24E-12	7.24E-06	4.73E-09	2.15E-15	16.018	94.091
270	1.03E-11	1.03E-05	6.74E-09	3.06E-15	18.020	94.689
300	1.41E-11	1.41E-05	9.25E-09	4.20E-15	20.022	96.288
350	2.24E-11	2.24E-05	1.47E-08	6.67E-15	23.359	97.011
400	3.35E-11	3.35E-05	2.19E-08	9.96E-15	26.696	98.340
450	4.77E-11	4.77E-05	3.12E-08	1.42E-14	30.033	99.071
500	6.54E-11	6.54E-05	4.28E-08	1.95E-14	33.370	99.071
600	1.13E-10	1.13E-04	7.40E-08	3.36E-14	40.044	100.000

Linear Interpolation:

Droplet Diameter (μm)	Droplet Volume (m ³)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m ³)	Particle Diameter (μm)	Mass Fraction (%)
130	1.15E-12	1.15E-06	7.52E-10	3.42E-16	8.676	82.023
150	1.77E-12	1.77E-06	1.16E-09	5.25E-16	10.011	88.012
					10.000	87.963

Mass Fraction of Cooling Tower PM ≤ PM ₁₀ :	0.880

Table B-13

POTENTIAL EMISSION INVENTORY WORKSHEET							
Seminole Generating Station						FWP1	
EMISSION SOURCE TYPE							
INTERNAL COMBUSTION ENGINES < 600 HP							
FACILITY AND SOURCE DESCRIPTION							
Emission Source Description:		Fire Water Pump					
Emission Control Method(s)/ID No.(s):		None					
Emission Point Description:		250 -HP Diesel Engine					
EMISSION ESTIMATION EQUATIONS							
Emission (lb/hr) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr)							
Emission (ton/yr) = Emission Factor (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)							
INPUT DATA AND EMISSIONS CALCULATIONS							
Operating Hours: 500 hrs/yr				Fuel Flow: 14.6 gal/hr			
No. of Engines: 1				Diesel Sulfur Content: 0.0015 weight %			
Heat Input: 2.00 MMBtu/hr (HHV)				Diesel Heat Content: 137,000 Btu/gal (HHV)			
Pollutant	Emission Factor g/hp-hr	Potential Emission Rates		Pollutant	Emission Factor (lb/MMBtu)	Potential Emission Rates	
		Per Unit (lb/hr)	Per Unit (tpy)			Per Unit (lb/hr)	Per Unit (tpy)
NO _x	2.10	1.16	0.29	1,3-Butadiene	3.91E-05	7.82E-05	1.96E-05
CO	2.60	1.43	0.36	Acetaldehyde	7.67E-04	1.53E-03	3.84E-04
VOC	0.90	0.50	0.12	Acrolein	9.25E-05	1.85E-04	4.63E-05
SO ₂	0.01	0.003	0.00	Benzene	9.33E-04	1.87E-03	4.67E-04
PM	0.15	0.08	0.02	Formaldehyde	1.18E-03	2.36E-03	5.90E-04
PM ₁₀	0.15	0.08	0.02	Naphthalene	1.30E-04	2.60E-04	6.50E-05
Highest HAP			1.29E-03	POM	1.68E-04	3.36E-04	8.40E-05
Total HAPs		1.32E-02	3.29E-03	Propylene	2.58E-03	5.16E-03	1.29E-03
				Toluene	4.09E-04	8.18E-04	2.05E-04
				Xylenes	2.85E-04	5.70E-04	1.43E-04
SOURCES OF INPUT DATA							
Parameter	Data Source						
Operating Hours (annual)	ECT, 2017.						
Fuel Flow Rate (gal/hr)	B&V, 2016.						
Emission Factors (Criteria Pollutants)	40 CFR Part 60 Subpart IIII except SO2 based on AP-42 emission factor and mass balance.						
Emission Factors (HAPs)	AP-42, Tables 3.3-1, EPA, October 1996						
Emission Factors (HAPs)	AP-42, Tables 3.3-2, EPA, October 1996						
NOTES AND OBSERVATIONS							
NO _x EF is based on 70% of NMHC+NO _x EF.							
VOC EF is based on 30% of NMHC+NO _x EF.							
POM = Polycyclic Organic Matter							
DATA CONTROL							
Data Collected by:	W. Karl					Date:	Oct-17
Calculated by:	W. Karl					Date:	Oct-17
Reviewed by:	A. Taggart					Date:	Oct-17

Table B-14

POTENTIAL EMISSION INVENTORY WORKSHEET							
Seminole Generating Station						FGH	
EMISSION SOURCE TYPE							
EXTERNAL COMBUSTION SOURCES < 100 MMBtu/hr							
FACILITY AND SOURCE DESCRIPTION							
Emission Source Description:		Two (2) Natural Gas-Fired Fuel Gas Heaters					
Emission Control Method(s)/ID No.(s):		None					
Emission Point Description:		9.99 MMBtu/hr Rated Capacity (HHV)					
EMISSION ESTIMATION EQUATIONS							
Emission (lb/hr) = Emission Factor (lb/MMBtu) x Rated Capacity (MMBtu/hr)							
Emission (ton/yr) = Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)							
INPUT DATA AND EMISSIONS CALCULATIONS							
Operating Hours:		8,760	hrs/yr				
Natural Gas Heat Content:		1,040	Btu/scf (HHV)				
No. of Fuel Gas Heaters		2					
Maximum Heat Input:		9.99	MMBtu/hr (HHV)				
Pollutant	Emission Factor (lb/MMcf)	Potential Emission Rates		Hazardous Air Pollutant (HAP)	Emission Factor (lb/10 ⁶ scf)	Potential Emission Rates	
		Per Unit (lb/hr)	Per Unit (tpy)			Per Unit (lb/hr)	Per Unit (tpy)
NO _x	100.0	0.96	8.4	2-Methylnaphthalene	2.4E-05	2.31E-07	2.02E-06
CO	84.0	0.81	7.1	Arsenic	2.0E-04	1.92E-06	1.68E-05
VOC	5.5	0.05	0.46	Benzene	2.1E-03	2.02E-05	1.77E-04
SO ₂	6.0	0.06	0.50	Cadmium	1.1E-03	1.06E-05	9.26E-05
PM	7.6	0.07	0.64	Chromium	1.4E-03	1.34E-05	1.18E-04
PM ₁₀	7.6	0.07	0.64	Cobalt	8.4E-05	8.07E-07	7.07E-06
Lead	5.00E-04	4.90E-06	4.29E-05	Dichlorobenzene	1.2E-03	1.15E-05	1.01E-04
Highest HAP		1.73E-02	1.51E-01	Fluoranthene	3.0E-06	2.88E-08	2.52E-07
Total HAPs		1.81E-02	1.59E-01	Fluorene	2.8E-06	2.69E-08	2.36E-07
				Formaldehyde	7.5E-02	7.20E-04	6.31E-03
				Hexane	1.8E+00	1.73E-02	1.51E-01
				Manganese	3.8E-04	3.65E-06	3.20E-05
				Mercury	2.6E-04	2.50E-06	2.19E-05
				Naphthalene	6.1E-04	5.86E-06	5.13E-05
				Nickel	2.1E-03	2.02E-05	1.77E-04
				Phenanthrene	1.7E-05	1.63E-07	1.43E-06
				Pyrene	5.0E-06	4.80E-08	4.21E-07
				Toluene	3.4E-03	3.27E-05	2.86E-04
SOURCES OF INPUT DATA							
Parameter		Data Source					
Operating Hours (annual)		ECT, 2017					
Natural Gas Heat Content (Btu/scf, HHV)		Seminole, 2017					
Maximum Heat Input (MMBtu/hr, HHV)		Seminole, 2017					
Emission Factor (NO _x , CO)		AP-42, Table 1.4-1, July 1998					
Emission Factors (VOC, PM/PM10)		AP-42, Table 1.4-2, July 1998					
Emission Factors (SO ₂)		AP-42, Table 1.4-2, July 1998					
Emission Factors (Lead)		AP-42, Table 1.4-2, July 1998					
Emission Factors (HAPs)		AP-42, Tables 1.4-3 and 1.4-4, July 1998					
NOTES AND OBSERVATIONS							
Only detected HAP compounds listed.							
DATA CONTROL							
Data Collected by:		W. Karl			Date:		Oct-17
Calculated by:		W. Karl			Date:		Oct-17
Reviewed by:		A. Taggart			Date:		Oct-17

APPENDIX C

SCCF Netting Analysis Calculations

Table	Description

Netting Analysis - Based on Shutdown of SGS Unit 1

- C-1 SCCF Project Netting Analysis Summary—Unit 1 Shutdown
- C-2 SCCF Project NO_x Baseline Actual Emissions - Unit 1
- C-3 SCCF Project SO₂ Baseline Actual Emissions - Unit 1
- C-4 SCCF Project CO₂e Baseline Actual Emissions - Unit 1
- C-5 SCCF Project CH₄ and N₂O Baseline Actual Emissions - Unit 1
- C-6 SCCF Project PM/PM₁₀/PM_{2.5} (filterable) Baseline Actual Emissions - Unit 1
- C-7 SCCF Project CPM Baseline Actual Emissions - Unit 1
- C-8 SCCF Project CO Baseline Actual Emissions - Unit 1
- C-9 SCCF Project VOC Baseline Actual Emissions - Unit 1
- C-10 SCCF Project Sulfuric Acid Mist (SAM) Baseline Actual Emissions - Unit 1

Netting Analysis - Based on Shutdown of SGS Unit 2

- C-11 SCCF Project Netting Analysis Summary—Unit 2 Shutdown
- C-12 SCCF Project NO_x Baseline Actual Emissions - Unit 2
- C-13 SCCF Project SO₂ Baseline Actual Emissions - Unit 2
- C-14 SCCF Project CO₂e Baseline Actual Emissions - Unit 2
- C-15 SCCF Project CH₄ and N₂O Baseline Actual Emissions - Unit 2
- C-16 SCCF Project PM/PM₁₀/PM_{2.5} (filterable) Baseline Actual Emissions - Unit 2
- C-17 SCCF Project CPM Baseline Actual Emissions - Unit 2
- C-18 SCCF Project CO Baseline Actual Emissions - Unit 2
- C-19 SCCF Project VOC Baseline Actual Emissions - Unit 2
- C-20 SCCF Project Sulfuric Acid Mist (SAM) Baseline Actual Emissions - Unit 2

Table C-1. SCCF Project Netting Analysis Summary—Unit 1 Shutdown

Pollutant	Unit 1 Baseline Actual Emissions* (tpy)	Potential Emissions† (tpy)	Net Emissions Increase/ (Decrease)‡ (tpy)	PSD Significant Level (tpy)	Trigger PSD?
NO _x	1,225	849	(376)	40	No
SO ₂	4,765	221	(4,544)	40	No
CO ₂ e	4,034,044	3,868,991	(165,053)	75,000	No
CO	1,439	779	(660)	100	No
VOC	15	90	75	40	Yes
PM	359	233	(126)	25	No
PM ₁₀	752	232	(520)	15	No
PM _{2.5}	752	232	(520)	10	No
SAM	197	142	(55)	7	No

*Based on highest actual 24-month annual average over past 5 years starting November 2012.

†Based on operating 8,760 hr/yr; maximum emissions based on all operating scenarios.

‡Potential emissions minus baseline actual emissions.

Sources: Clean Air Markets, Acid Rain Program, 2017.
FDEP, 2017.
SECI, 2017.
ECT, 2017.

Table C-2. SCCF Project NO_x Baseline Actual Emissions - SGS Unit 1

	Nov 2014 - Oct 2016	Jan 2015 - Dec 2016	Feb 2015 - Jan 2017	Mar 2015 - Feb 2017	Apr 2015 - Mar 2017
SGS Unit 1	1,127	1,137	1,141	1,169	1,225

Note: Maximum annual NO_x emissions (tpy) based on 24-month rolling annual average.
 Five highest 24-month annual averages shown within the 5-year period immediately
 preceding the date a complete permit application is received by FDEP; highest
 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.
 SECI, 2017.
 ECT, 2017.

Table C-3. SCCF Project SO₂ Baseline Actual Emissions - SGS Unit 1

	Dec 2012 - Nov 2014	Jan 2013 - Dec 2014	Feb 2013 - Jan 2015	Mar 2013 - Feb 2015	Apr 2013 - Mar 2015
SGS Unit 1	4,765	4,746	4,717	4,680	4,471

Note:

1. Maximum annual SO₂ emissions (tpy) based on 24-month rolling annual average.
2. Actual emissions adjusted for maximum SO₂ permit limit of 0.25 lb/MMBtu effective March 1, 2016.
3. Five highest 24-month annual averages shown within the 5-year period immediately preceding the date a complete permit application is received by FDEP; highest 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.
SECI, 2017.
ECT, 2017.

Table C-4. SCCF Project GHG Baseline Actual Emissions - SGS Unit 1

	Baseline Emissions (tpy)				
	Aug 2012 - Jul 2014	Dec 2012 - Nov 2014	Jan 2013 - Dec 2014	Feb 2013 - Jan 2015	Apr 2015 - Mar 2017
CO ₂	3,858,303	3,923,104	3,907,358	3,883,466	4,033,498
Methane	456	464	462	459	477
N ₂ O	<u>66</u>	<u>67</u>	<u>67</u>	<u>67</u>	<u>69</u>
CO ₂ e	3,858,825	3,923,635	3,907,887	3,883,992	4,034,044

Note: Maximum annual CO₂ emissions (tpy) based on 24-month rolling annual average.

Five highest 24-month annual averages shown within the 5-year period immediately preceding the date a complete permit application is received by FDEP; highest 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.
SECI, ECT; 2017.

Table C-5. SCCF Project Methane and N₂O Baseline Emissions - SGS Unit 1

	Baseline Emissions				
	Aug 2012 - Jul 2014	Dec 2012 - Nov 2014	Jan 2013 - Dec 2014	Feb 2013 - Jan 2015	Apr 2015 - Mar 2017
Heat input (MMBtu/yr)	37,605,314	38,236,899	38,083,430	37,850,572	39,312,834
Methane (tpy)	456	464	462	459	477
N ₂ O (tpy)	66	67	67	67	69

Note: Methane and N₂O emissions based on 1.1 E-02 kg/MMBtu and 1.6E-03 kg/MMBtu, respectively.

Ref: 40 CFR 98, Subpart C, Table C-2.

Methane (CH₄) and nitrous oxide (N₂O) emissions were based on the same 24-month periods used to calculate the carbon dioxide (CO₂) emissions.

Sources: Clean Air Markets, Acid Rain Program, 2017.

SECI, 2017.

ECT, 2017.

Table C-6. SCCF Project PM/PM₁₀/PM_{2.5} (filterable) Baseline Actual Emissions - SGS Unit 1

	Baseline Emissions				
	Dec 2014 - Nov 2016	Jan 2015 - Dec 2016	Feb 2015 - Jan 2017	Mar 2015 - Feb 2017	Apr 2015 - Mar 2017
Heat input (MMBtu/yr)	36,023,321	36,503,399	36,613,296	37,421,348	39,312,834
PM/PM ₁₀ /PM _{2.5} EF (lb/MMBtu)	0.018	0.018	0.018	0.018	0.018
PM/PM ₁₀ /PM _{2.5} (tpy)	329	333	334	341	359

Note: PM/PM₁₀/PM_{2.5} emission factor of 0.01825 lb/MMBtu based on an average of four quarterly stack tests conducted in 2016 on Unit 1.

Five highest 24-month annual averages shown within the 5-year period immediately preceding the date a complete permit application is received by FDEP; highest 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.

SECI, 2017.

ECT, 2017.

Table C-7. SCCF Project Condensible PM (CPM) Baseline Actual Emissions - SGS Unit 1

	Baseline Emissions				
	Dec 2014 - Nov 2016	Jan 2015 - Dec 2016	Feb 2015 - Jan 2017	Mar 2015 - Feb 2017	Apr 2015 - Mar 2017
Heat input (MMBtu/yr)	36,023,321	36,503,399	36,613,296	37,421,348	39,312,834
CPM EF (lb/MMBtu)	0.02	0.02	0.02	0.02	0.02
CPM (tpy)	360	365	366	374	393

Note: CPM emission factor based on AP-42, Table 1.1-5.

Five highest 24-month annual averages shown within the 5-year period immediately preceding the date a complete permit application is received by FDEP; highest 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.

SECI, 2017.

ECT, 2017.

Table C-8. SCCF Project CO Baseline Actual Emissions - SGS Unit 1

	Oct 2014 - Sept 2016	Nov 2014 - Oct 2016	Dec 2014 - Nov 2016	Jan 2015 - Dec 2016	Feb 2015 - Jan 2017
SGS Unit 1	1,429	1,418	1,424	1,439	1,419

Note: Maximum annual CO emissions (tpy) based on 24-month rolling annual average.
 Five highest 24-month annual averages shown within the 5-year period immediately
 preceding the date a complete permit application is received by FDEP; highest
 24-month annual average shown in **bold**.

Sources: SECI, 2017.
 ECT, 2017.

Table C-9. SCCF Project VOC Baseline Actual Emissions - SGS Unit 1

	Baseline Emissions				
	Dec 2014 - Nov 2016	Jan 2015 - Dec 2016	Feb 2015 - Jan 2017	Mar 2015 - Feb 2017	Apr 2015 - Mar 2017
Heat input (MMBtu/yr)	36,023,321	36,503,399	36,613,296	37,421,348	39,312,834
VOC EF (lb/ton of coal)	0.017	0.017	0.017	0.017	0.017
VOC EF (lb/MMBtu)	0.0007	0.0007	0.0007	0.0007	0.0007
VOC (tpy)	12	13	13	13	13

Note: VOC emission factor based on 0.017 lb VOC/ton coal based on 2010 stack test on Unit 1.
VOC emission factor (lb/MMBtu) based on heat content of coal of 12,400 Btu/lb (HHV).
Five highest 24-month annual averages shown within the 5-year period immediately preceding the date a complete permit application is received by FDEP; highest 24-month annual average shown in **bold**.

Sources: SECI, 2017.
ECT, 2017.

Table C-10. SCCF Project SAM Baseline Actual Emissions - SGS Unit 1

	Baseline Emissions				
	Dec 2014 - Nov 2016	Jan 2015 - Dec 2016	Feb 2015 - Jan 2017	Mar 2015 - Feb 2017	Apr 2015 - Mar 2017
Heat input (MMBtu/yr)	36,023,321	36,503,399	36,613,296	37,421,348	39,312,834
SAM EF (lb/MMBtu)	0.01	0.01	0.01	0.01	0.01
SAM (tpy)	180	183	183	187	197

Note: SAM emission factor of 0.01 lb/MMBtu based on 2016 stack test conducted on Unit 1.

Five highest 24-month annual averages shown within the 5-year period immediately preceding the date a complete permit application is received by FDEP; highest 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.

SECI, 2017.

ECT, 2017.

Table C-11. SCCF Project Netting Analysis Summary—Unit 2 Shutdown

Pollutant	Unit 2 Baseline Actual Emissions* (tpy)	Potential Emissions† (tpy)	Net Emissions Increase/ (Decrease)‡ (tpy)	PSD Significant Level (tpy)	Trigger PSD?
NO _x	1,110	849	(261)	40	No
SO ₂	4,897	221	(4,676)	40	No
CO ₂ e	4,075,158	3,868,991	(206,167)	75,000	No
CO	1,435	779	(656)	100	No
VOC	15	90	75	40	Yes
PM	352	233	(119)	25	No
PM ₁₀	750	232	(518)	15	No
PM _{2.5}	750	232	(518)	10	No
SAM	199	142	(57)	7	No

*Based on highest actual 24-month annual average over past 5 years starting November 2012.

†Based on operating 8,760 hr/yr; maximum emissions based on all operating scenarios.

‡Potential emissions minus baseline actual emissions.

Sources: Clean Air Markets, Acid Rain Program, 2017.
SECI, 2017.
ECT, 2017.

Table C-12. SCCF Project NO_x Baseline Actual Emissions - SGS Unit 2

	Dec 2014 - Nov 2016	Jan 2015 - Dec 2016	Feb 2015 - Jan 2017	Mar 2015 - Feb 2017	Apr 2015 - Mar 2017
SGS Unit 2	1,073	1,088	1,106	1,110	1,110

Note: Maximum annual NO_x emissions (tpy) based on 24-month rolling annual average.
 Five highest 24-month annual averages shown within the 5-year period immediately
 preceding the date a complete permit application is received by FDEP; highest
 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.
 SECI, 2017.
 ECT, 2017.

Table C-13. SCCF Project SO₂ Baseline Actual Emissions - SGS Unit 2

	May 2013 - Apr 2015	Jul 2013 - Jun 2015	Aug 2013 - Jul 2015	Sept 2013 - Aug 2015	Oct 2013 - Sept 2015
SGS Unit 2	4,881	4,865	4,856	4,860	4,897

Note:

1. Maximum annual SO₂ emissions (tpy) based on 24-month rolling annual average.
2. Actual emissions adjusted for maximum SO₂ permit limit of 0.25 lb/MMBtu effective March 1, 2016.
3. Five highest 24-month annual averages shown within the 5-year period immediately preceding the date a complete permit application is received by FDEP; highest 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.
SECI, 2017.
ECT, 2017.

Table C-14. SCCF Project GHG Baseline Actual Emissions - SGS Unit 2

	Baseline Emissions (tpy)				
	Oct 2013 - Sept 2015	Nov 2013 - Oct 2015	Dec 2013 - Nov 2015	Jan 2014 - Dec 2015	Feb 2014 - Jan 2016
CO ₂	4,026,982	4,039,545	4,074,629	4,057,824	4,033,582
Methane	456	464	462	459	477
N ₂ O	<u>66</u>	<u>67</u>	<u>67</u>	<u>67</u>	<u>69</u>
CO ₂ e	4,027,504	4,040,076	4,075,158	4,058,350	4,034,128

Note: Maximum annual CO₂ emissions (tpy) based on 24-month rolling annual average.

Five highest 24-month annual averages shown within the 5-year period immediately preceding the date a complete permit application is received by FDEP; highest 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.
SECI, ECT; 2017.

Table C-15. SCCF Project Methane and N₂O Baseline Emissions - SGS Unit 2

	Baseline Emissions				
	Jun 2012 - May 2014	Sept 2012 - Aug 2014	Nov 2013 - Oct 2015	Dec 2013 - Nov 2015	Jan 2014 - Dec 2015
Heat input (MMBtu/yr)	39,433,781	39,472,126	39,371,528	39,713,481	39,549,685
Methane (tpy)	478	479	477	482	480
N ₂ O (tpy)	70	70	69	70	70

Note: Methane and N₂O emissions based on 1.1 E-02 kg/MMBtu and 1.6E-03 kg/MMBtu, respectively.

Ref: 40 CFR 98, Subpart C, Table C-2.

Five highest 24-month annual averages shown within the 5-year period immediately preceding the date a complete permit application is received by FDEP; highest 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.

SECI, 2017.

ECT, 2017.

Table C-16. SCCF Project PM/PM₁₀/PM_{2.5} (filterable) Baseline Actual Emissions - SGS Unit 2

	Baseline Emissions				
	Jun 2012 - May 2014	Sept 2012 - Aug 2014	Nov 2013 - Oct 2015	Dec 2013 - Nov 2015	Jan 2014 - Dec 2015
Heat input (MMBtu/yr)	39,433,781	39,472,126	39,371,528	39,713,481	39,549,685
PM/PM ₁₀ /PM _{2.5} EF (lb/MMBtu)	0.018	0.018	0.018	0.018	0.018
PM/PM ₁₀ /PM _{2.5} (tpy)	350	350	349	352	351

Note: PM/PM₁₀/PM_{2.5} emission factor of 0.01775 lb/MMBtu based on an average of four quarterly stack tests conducted in 2016 on Unit 2.

Five highest 24-month annual averages shown within the 5-year period immediately preceding the date a complete permit application is received by FDEP; highest 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.

SECI, 2017.

ECT, 2017.

Table C-17. SCCF Project Condensable Particulate Matter (CPM) Baseline Actual Emissions - SGS Unit 2

	Baseline Emissions				
	Jun 2012 - May 2014	Sept 2012 - Aug 2014	Nov 2013 - Oct 2015	Dec 2013 - Nov 2015	Jan 2014 - Dec 2015
Heat input (MMBtu/yr)	39,433,781	39,472,126	39,371,528	39,713,481	39,549,685
CPM EF (lb/MMBtu)	0.02	0.02	0.02	0.02	0.02
CPM (tpy)	394	395	394	397	395

Note: CPM emission factor based on AP-42, Table 1.1-5.

Five highest 24-month annual averages shown within the 5-year period immediately preceding the date a complete permit application is received by FDEP; highest 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.

SECI, 2017.

ECT, 2017.

Table C-18. SCCF Project CO Baseline Actual Emissions - SGS Unit 2

	Nov 2014 - Oct 2016	Dec 2014 - Nov 2016	Jan 2015 - Dec 2016	Feb 2015 - Jan 2017	Mar 2015 - Feb 2017
SGS Unit 2	1,387	1,382	1,435	1,404	1,372

Note: Maximum annual NO_x emissions (tpy) based on 24-month rolling annual average.
 Five highest 24-month annual averages shown within the 5-year period immediately
 preceding the date a complete permit application is received by FDEP; highest
 24-month annual average shown in **bold**.

Sources: SECI, 2017.
 ECT, 2017.

Table C-19. SCCF Project VOC Baseline Actual Emissions - SGS Unit 2

	Baseline Emissions				
	Jun 2012 - May 2014	Sept 2012 - Aug 2014	Nov 2013 - Oct 2015	Dec 2013 - Nov 2015	Jan 2014 - Dec 2015
Heat input (MMBtu/yr)	39,433,781	39,472,126	39,371,528	39,713,481	39,549,685
VOC EF (lb/ton of coal)	0.017	0.017	0.017	0.017	0.017
VOC EF (lb/MMBtu)	0.0007	0.0007	0.0007	0.0007	0.0007
VOC (tpy)	14	14	13	14	14

Note: VOC emission factor based on 0.017 lb VOC/ton coal based on 2010 stack test on Unit 1.
 VOC emission factor (lb/MMBtu) based on heat content of coal of 12,400 Btu/lb (HHV).
 Five highest 24-month annual averages shown within the 5-year period immediately preceding the date a complete permit application is received by FDEP; highest 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.
 SECI, 2017.
 ECT, 2017.

Table C-20. SCCF Project SAM Baseline Actual Emissions - SGS Unit 2

	Baseline Emissions				
	Jun 2012 - May 2014	Sept 2012 - Aug 2014	Nov 2013 - Oct 2015	Dec 2013 - Nov 2015	Jan 2014 - Dec 2015
Heat input (MMBtu/yr)	39,433,781	39,472,126	39,371,528	39,713,481	39,549,685
SAM EF (lb/MMBtu)	0.01	0.01	0.01	0.01	0.01
SAM (tpy)	197	197	197	199	198

Note: SAM emission factor of 0.01 lb/MMBtu based on 2016 stack test conducted on Unit 2.

Five highest 24-month annual averages shown within the 5-year period immediately preceding the date a complete permit application is received by FDEP; highest 24-month annual average shown in **bold**.

Sources: Clean Air Markets, Acid Rain Program, 2017.

SECI, 2017.

ECT, 2017.

Appendix D

RBLC Tables

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
OK-0129	CHOUTEAU POWER PLANT	01/23/09	02/18/10		1882 MMBTU/H	GOOD COMBUSTION	0.3 PPM	BACT-PSD
*CT-0161	KILLINGLY ENERGY CENTER	06/30/17	08/28/17	550 MW Combined Cycle Plant	2969 MMBtu/hr	Oxidation Catalyst	0.7 PPMVD @ 1	BACT-PSD
NJ-0082	WEST DEPTFORD ENERGY STATION	07/18/14	05/02/16	An existing Electric Generating Facility with a PSD permit. A new project consisting of a 427 MW Siemens Combined Cycle combustion turbine unit is being added to the existing facility. The new project is subject to BACT/LAER	20282 MMCF/YR	Oxidation catalysts and use of Natural gas a clean burning fuel	0.7 PPMVD @ 215	LAER
NY-0104	CPV VALLEY ENERGY CENTER	08/01/13	09/28/17	CPV Valley Energy Center is a 680 MW combined cycle electric generating facility located in Middletown, NY. The combustion turbines are rated at 2,234 MMBTU/H firing natural gas and 2,145 MMBTU/H firing diesel fuel. The duct burners are rated for 500 MMBTU/H firing natural gas. In addition to the turbines their emission limits for the auxiliary boiler (73.5 MMBTU/H), emergency generator, fire pump, and gas heater.		Good combustion practice and oxidation catalyst.	0.7 PPMVD @	LAER
VA-0321	BRUNSWICK COUNTY POWER STATION	03/12/13	03/11/16	New, combined-cycle, natural gas-fired, electrical power generating facility.	3442 MMBTU/H	Oxidation catalyst; good combustion practices.	0.7 PPMVD	BACT-PSD
CT-0157	CPV TOWANTIC, LLC	11/30/15	02/19/16	805 MW Combined Cycle Power Plant	21200000 MMBtu/12 months	Oxidation Catalyst	1 PPMVD @	BACT-PSD
CT-0158	CPV TOWANTIC, LLC	11/30/15	02/19/16	805 MW Combined Cycle Plant	21200000 MMBtu/yr	Oxidation Catalyst	1 PPMVD @	BACT-PSD
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	03/09/16	03/16/16	Fossil-fueled power plant, consisting of a 3-on-1 combined cycle unit and auxiliary equipment. The combined cycle unit consists of three GE 7HA.02 turbines, each with nominal generating capacity of 350 MW. The total generating capacity for the combined cycle unit is 1,600 MW.	3096 MMBtu/hr per turbine	Complete combustion minimizes VOC	1 PPMVD @ 1	BACT-PSD
IA-0107	MARSHALLTOWN GENERATING STATION	04/14/14	05/04/16	Utility electric generating station	2258 mmBtu/hr	catalytic oxidizer	1 PPM	BACT-PSD
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	12/03/12	05/04/16	STATIONARY ELECTRIC UTILITY GENERATING STATION	2300 MMBTU/H	OXIDIZED CATALYST	1 PPMVD	BACT-PSD
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	01/30/14	05/05/16	Footprint Power Salem Harbor Development LP (the Permittee) proposes to construct and operate a nominal 630 Megawatt (MW) natural gas fired, quick start (capable of producing 300 MW within 10 minutes of startup) combined cycle electric generating facility (the Facility) at Salem Harbor Station. With duct firing, the proposed Facility will be capable of generating an additional 62 MW, for a total of 692 MW. Emission units include two 315 MW (nominal) GE Model 107F Series 5 combustion turbine generators, each with dedicated heat recovery steam generator, duct burner and 31 MW (estimated) steam turbine generator, dispatchable independently of one another by ISO-NE; one 80 mmBtu/hr auxiliary boiler, one 750 kW emergency engine-generator, and one 371 bhp emergency engine-fire-pump.	2449 MMBTU/H	Oxidation catalyst	1 PPMVD @ 1	OTHER CASE-BY-CASE
MD-0041	CPV ST. CHARLES	04/23/14	03/16/16	725 MW COMBINED-CYCLE NATURAL GAS-FIRED POWER PLANTFACILITY-WIDE PM10 EMISSION LIMIT = 96.6 TONS/YR FACILITY-WIDE SAM EMISISON LIMIT < 7.0 TONS/YR FACILITY-WIDE PM2.5 (TOTAL) EMISSION LIMIT < 100.0 TONS/YR	725 MEGAWATT	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1 PPMVD @	LAER
MD-0045	MATTAWOMAN ENERGY CENTER	11/13/15	05/13/16	990 MW COMBINED-CYCLE NATURAL GAS-FIRED POWER PLANTNOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE)	286 MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1 PPMVD @	LAER
MD-0046	KEYS ENERGY CENTER	10/31/14	05/13/16	735 MW COMBINED-CYCLE NATURAL GAS-FIRED POWER PLANT NOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE)	235 MW	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1 PPMVD @	LAER

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	03/07/14	05/02/16	This is a new 625 MW combined cycle project at an existing facility. The project will comprise of two combustion turbines, EITHER GE7FA.05 OR Siemens SGT6 5000F, with two duct burners, two Heat Recovery Steam Generators (HRS), one steam turbine, one 250 HP fire pump and a 3-cell auxiliary cooling tower. Each turbine will be equipped with Selective Catalytic Reduction System (SCR) for control of NOx emissions and Oxidation Catalyst for control of CO and VOC. The heat input rate of the Siemens turbine will be 2,356 MMBtu/hr(HHV) with a 62.1 duct burner MMBtu/hr(HHV). The heat input rate of each GE turbine will be 2,312 MMBtu/hr(HHV) with a 164.4 duct burner MMBtu/hr(HHV).	33691 MMCF/YR	Oxidation Catalyst and use of natural gas a clean burning fuel	1 PPMVD@1	LAER
NJ-0082	WEST DEPTFORD ENERGY STATION	07/18/14	05/02/16	An existing Electric Generating Facility with a PSD permit. A new project consisting of a 427 MW Siemens Combined Cycle combustion turbine unit is being added to the existing facility. The new project is subject to BACT/LAER	20282 MMCF/YR	Oxidation catalyst and use of natural gas a clean burning fuel	1 PPMVD@1	LAER
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	07/19/16	11/03/16	NEW 633 MEGAWATT (MW) GROSS FACILITY CONSISTING OF 1.ONE GENERAL ELECTRIC (GE) 7HA.02 CCCT NOMINALLY RATED AT 380 MW AT ISO CONDITIONS WITHOUT DUCT FIRING WITH A MAXIMUM HEAT INPUT RATE OF: O 3,462 MMBTU/HR(HHV) AT (0) DEGREES F, 100% LOAD COMBUSTING NATURAL GAS O 3,613 MMBTU/HR(HHV) AT (0) DEGREES F, 100% LOAD COMBUSTING ULSD WHICH WILL BE THE BACKUP FUEL OTHER EQUIPMENT INCLUDES: 2.ONE NATURAL GAS-FIRED DUCT BURNER (MAXIMUM HEAT INPUT OF 599 MMBTU/HR(HHV)) FOR SUPPLEMENTAL FIRING. 3.ONE 97.5 MMBTU/HR(HHV) NATURAL GAS FIRED AUXILIARY BOILER, EQUIPPED WITH LOW NOX BURNERS AND FLUE GAS RECIRCULATION FOR CONTROL OF NOX EMISSIONS; 4.ONE 2.25 MMBTU/HR(HHV), 327 BRAKE HORSEPOWER, ULSD FIRED EMERGENCY FIRE PUMP; 5.ONE 14.4 MMBTU/HR(HHV), APPROXIMATELY 1,500 KW ULSD FIRED EMERGENCY GENERATOR; AND 6.ONE 8-CELL, 124,800 GALLON PER MINUTE (GPM) MECHANICAL INDUCED DRAFT COOLING TOWER.	8040 H/YR	Oxidation catalyst and good combustion practices	1 PPMVD@1	LAER
OH-0352	OREGON CLEAN ENERGY CENTER	06/18/13	05/04/16	799 Megawatt Combined Cycle Combustion Turbine Power Plant	515600 MMSCF/rolling 12-months	oxidation catalyst	1 PPM	BACT-PSD
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	10/10/12	04/03/15		3277 MMBTU/H	Oxidation Catalyst	1 PPMVD	LAER
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	01/31/13	05/27/16	This plan approval is for the construction of two natural-gas-fired combined cycle powerblocks where each powerblock consists of a combustion turbine and heat recovery steam generator with duct burner. The two powerblocks constructed pursuant to this plan approval will be either the two powerblocks rated 472 megawatts (MW) (P101 and P102) or the powerblocks rated 458 MW (P103 and P104). Additionally, this plan approval is for the construction of a 1464 bhp diesel-fired emergency generator, 460 bhp dieselfired fire pump, 1600 gallon diesel tank, 300 gallon diesel tank, two 15,000 gallon (each) lube oil tanks and ancillary electrical equipment.		CO Catalyst	1 PPMVD	BACT-PSD

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
PA-0288	SUNBURY GENERATION LP/SUNBURY SES	04/01/13	05/27/16	This plan approval is for the repowering of the Sunbury Generation facility. This project will be for the construction of three (3) natural gas fired F class combustion turbines coupled with three (3) heat recovery steam generators (HSRGs) equipped with natural gas fired duct burners. The project will also be for the construction of a natural gas fired auxiliary boiler to assist with startup and shutdown activities and a small natural gas fired dew point heater. As part of the project all of the facility's existing coal fired utility boilers will be permanently retired.	2538000 MMBTU/H	Oxidation Catalyst	1 PPM	OTHER CASE-BY-CASE
*PA-0309	LACKAWANNA ENERGY CTR/JESSUP	12/23/15	07/20/17	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3) CT/HRSG sharing one (1) steam turbine. The entire power block is rated at 1,500 MW. Additional equipment includes: one (1) 2,000 kW diesel-fired emergency generator one (1) 315 HP diesel-fired emergency fire water pump one (1) 184.8 MM BTU/hr natural gas fired boiler one (1) 12 MMBTU/hr natural gas fuel gas heater two (2) Diesel fuel storage tanks four (4) lubricating oil tanks one (1) aqueous ammonia storage tank		Oxidation catalyst, combustion controls, exclusive natural gas	1 PPNDV @	LAER
*PA-0310	CPV FAIRVIEW ENERGY CENTER	09/02/16	07/31/17	This plan approval authorizes CPV Fairview, LLC to construct and temporarily operate the Fairview Energy Center. Air contamination sources and air cleaning devices authorized for construction and temporary operation under this plan approval include: A combined cycle electric generating unit consisting of two (2) General Electric ("GE") 7HA.02 "H"-class combustion turbines each with maximum fuel type-based heat input of 3,338-MMBtu/hr (natural gas), 3,274-MMBtu/hr (ULSD), 3,199 MMBtu/hr (ethane blend), and equipped with dry low-NOx combustors and evaporative turbine intake cooling; two (2) heat recovery steam generators (HRSGs) each equipped with a low-NOx duct burner with maximum heat input of 425-MMBtu/hr, and a common steam turbine generator. Exhaust emissions from each combined cycle electric generating unit will be controlled by oxidation catalyst and selective catalytic reduction (SCR). - One (1) up to 12-cell mechanical draft wet cooling tower with high-efficiency drift eliminator. - One (1) natural gas-fired auxiliary boiler with maximum heat input of 92.4 MMBtu/hr. - One (1) natural gas-fired dew point heater with maximum heat input of 12.8 MMBtu/hr. - One (1) natural gas-fired dew point heater with maximum heat input of 3.2 MMBtu/hr. - Two (2) 1,500-ekW diesel-fired emergency genset engines. - One (1) 422-bhp diesel-fired fire water pump engine. - One (1) 1,000,000-gallon ULSD storage tank. - Eight (8) sulfur hexafluoride (SF6) circuit breakers. - Plant roadways.			1 PPM DV @	BACT-PSD

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBL ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	12/19/14	05/09/16	NRG Texas is proposing to construct an additional electric power generation station at the Bertron Power Project which will generate electric power for sale on the wholesale electric market. The Bertron Power Project will include two power blocks that can be operated in combined cycle mode.	240 MW	oxidation catalyst	1 PPMVD	BACT-PSD
*TX-0817	CHOCOLATE BAYOU STEAM GENERATING (CBSG) STATION	02/17/17	08/07/17	support facility providing steam and electricity	50 MW	OXIDATION CATALYST	1 PPMVD	BACT-PSD
*NJ-0085	MIDDLESEX ENERGY CENTER, LLC	07/19/16	08/09/16	New 633 megawatt (MW) gross facility consisting of 1.One General Electric (GE) 7HA.02 CCCT nominally rated at 380 MW at ISO conditions without duct firing with a maximum heat input rate of: o 3,462 MMBtu/hr(HHV) at (0) degrees F, 100% load combusting natural gas o 3,613 MMBtu/hr(HHV) at (0) degrees F, 100% load combusting ULSD which will be the backup fuel Other equipment includes: 2.One natural gas-fired duct burner (maximum heat input of 599 MMBtu/hr(HHV)) for supplemental firing. 3.One 97.5 MMBtu/hr(HHV) natural gas fired auxiliary boiler, equipped with low NOx burners and flue gas recirculation for control of NOx emissions; 4.One 2.25 MMBtu/hr(HHV), 327 brake horsepower, ULSD fired emergency fire pump; 5.One 14.4 MMBtu/hr(HHV), approximately 1,500 kW ULSD fired emergency generator; and 6.One 8-cell, 124,800 gallon per minute (gpm) mechanical induced draft cooling tower.	8040 H/YR	Oxidation catalyst and good combustion practices	1 PPMVD@1	LAER
FL-0285	PROGRESS BARTOW POWER PLANT	01/26/07	06/12/08	PROGRESS ENERGY FLORIDA OPERATES THE BARTOW PLANT, WHICH IS AN EXISTING POWER PLANT (SIC NO. 4911). THE PLANT CURRENTLY (2007)CONSISTS OF: Â€THREE FOSSIL FUEL FIRED STEAM GENERATING UNITS DESIGNATED AS UNITS 1, 2 AND 3 THAT PRODUCE 120, 120 AND 225 MEGAWATTS (MW) OF ELECTRICAL POWER RESPECTIVELY; Â€FOUR SIMPLE CYCLE UNITS DESIGNATED AS GAS COMBUSTION TURBINE PEAKING UNITS NOS. P-1, P-2, P-3 AND P-4 EACH OF WHICH HAS A NOMINAL CAPACITY OF 56 MW; Â€ADDITIONAL EMISSIONS UNITS INCLUDE A PIPELINE HEATING BOILER AND RELOCATABLE DIESEL GENERATORS; AND Â€MISCELLANEOUS UNREGULATED/INSIGNIFICANT EMISSIONS UNITS AND/OR ACTIVITIES INCLUDING FUEL STORAGE TANKS AND GAS TANKS THAT CAN BE LOCATED AT VARIOUS PEF POWER PLANTS. THIS NEW PERMIT (REPOWERING PROJECT) IS FOR THE CONSTRUCTION OF A 1280 MW (4-ON-1) COMBINED CYCLE UNIT SYSTEM AND A NOMINAL 195 MW GAS-FIRED SIMPLE CYCLE UNIT. THE EXISTING BOILERS WILL BE SHUTDOWN.	1972 MMBTU/H	GOOD COMBUSTION	1.2 PPMVD	BACT-PSD

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	07/30/08	01/05/11	THE F&L WEST COUNTY ENERGY CENTER (WCEC) WAS PREVIOUSLY APPROVED FOR CONSTRUCTION AS A NOMINAL 2,500 MEGAWATT (MW) GREENFIELD POWER PLANT. THE PREVIOUSLY APPROVED CONSTRUCTION UNDERWAY (PHASE I) IS FOR TWO NOMINAL 1,250 MW GAS-FIRED COMBINED CYCLE UNITS (UNITS 1 AND 2) THAT WILL USE ULTRALOW SULFUR DIESEL (ULSD) FUEL OIL (FO) AS BACKUP FUEL. PHASE 2: UNITS 1 AND 2 WILL EACH CONSIST OF: THREE NOMINAL 250 MEGAWATT (MW) MODEL 501G COMBUSTION TURBINE-ELECTRICAL GENERATORS (CTG) WITH EVAPORATIVE INLET COOLING SYSTEMS; THREE SUPPLEMENTARY-FIRED HEAT RECOVERY STEAM GENERATORS (HRSG) WITH SELECTIVE CATALYTIC REDUCTION (SCR) REACTORS; ONE NOMINAL 428 MMBTU/HOUR (LOWER HEATING VALUE - LHV) GAS-FIRED DUCT BURNER (DB) LOCATED WITHIN EACH OF THE THREE HRSG; THREE 149 FEET EXHAUST STACKS; ONE 26 CELL MECHANICAL DRAFT COOLING TOWER; AND A COMMON NOMINAL 500 MW STEAM-ELECTRICAL GENERATOR (STG). PREVIOUSLY APPROVED ANCILLARY EQUIPMENT INCLUDES: FOUR EMERGENCY GENERATORS; TWO NATURAL GAS FIRED FUEL HEATERS; ONE EMERGENCY DIESEL FIRED PUMP; TWO DIESEL FUEL STORAGE TANKS; TWO AUXILIARY STEAM BOILERS; AND OTHER ASSOCIATED SUPPORT EQUIPMENT. THIS PERMIT AUTHORIZES CONSTRUCTION OF ANOTHER 1,250 MW GAS-FIRED COMBINED CYCLE UNIT (UNIT 3) IDENTICAL TO THE DESCRIPTION GIVEN ABOVE FOR UNITS 1 AND 2. ADDITIONAL ANCILLARY EQUIPMENT FOR UNIT 3 WILL INCLUDE TWO EMERGENCY GENERATORS, TWO NATURAL GAS FIRED FUEL HEATERS AND ASSOCIATED EQUIPMENT. UNIT 3 WILL USE SOME OF THE INFRASTRUCTURE AND ANCILLARY EQUIPMENT ALREADY UNDER CONSTRUCTION INCLUDING THE DIESEL STORAGE TANKS AND AUXILIARY BOILERS.	2333 MMBTU/H	0	1.2 PPMVD	BACT-PSD
FL-0337	POLK POWER STATION	10/14/12	11/07/14	The Polk Power Station consists of: a nominal 250 MW (net) solid fuel-based integrated gasification and combined cycle (Unit 1) including a sulfuric acid plant and an auxiliary boiler; four natural gas-fueled nominal 165 MW simple cycle combustion turbine-electrical generators (CTGs) designated as Units 2, 3, 4 and 5; and ancillary equipment. Units 2 and 3 are equipped with backup fuel oil-firing capability.	1160 MW	fuel Sulfur limits	1.4 PPMVD @	BACT-PSD
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	08/16/11	12/12/11	1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWATER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	7146 MMBTU/H	GOOD COMBUSTION PRACTICES	1.4 PPMVD @	BACT-PSD
*PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	02/12/16	07/12/17	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.	0	Ox Cat and good combustion practices	1.4 PPMVD @	LAER

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
*VA-0325	GREENSVILLE POWER STATION	06/17/16	02/24/17	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas.	3227 MMBTU/HR	Oxidation Catalyst and good combustion practices	1.4 PPMVD	N/A
FL-0286	FPL WEST COUNTY ENERGY CENTER	01/10/07	03/03/09	THE FPL WEST COUNTY ENERGY CENTER WILL BE A NOMINAL 2,500 MEGAWATT (MW) GREENFIELD POWER PLANT (2007). THE INITIAL PHASE IS THE CONSTRUCTION OF TWO NOMINAL 1,250 MW GAS-FIRED COMBINED CYCLE UNITS THAT WILL USE ULTRALOW SULFUR (ULS) FUEL OIL AS BACKUP FUEL. EACH COMBINED CYCLE UNIT SYSTEM (TWO "3-ON-1" WILL CONSIST OF: THREE NOMINAL 250 MEGAWATT MODEL 501G GAS TURBINE-ELECTRICAL GENERATOR SETS WITH EVAPORATIVE INLET COOLING SYSTEMS; THREE SUPPLEMENTARY-FIRED HEAT RECOVERY STEAM GENERATORS (HRSG'S) WITH SCR REACTORS; ONE NOMINAL 428 MMBTU/HOUR (LHV) GAS-FIRED DUCT BURNER LOCATED WITHIN EACH OF THE THREE HRSG'S; THREE 149 FEET EXHAUST STACKS; ONE 26 CELL MECHANICAL DRAFT COOLING TOWER; AND A COMMON NOMINAL 500 MW STEAM-ELECTRICAL GENERATOR. ADDITIONAL ANCILLARY EQUIPMENT WILL INCLUDE: FOUR EMERGENCY GENERATORS; TWO NATURAL GAS FIRED FUEL HEATERS; TWO DIESEL FUEL STORAGE TANKS; TWO AUXILIARY STEAM BOILERS; AND OTHER ASSOCIATED SUPPORT EQUIPMENT.	2333 MMBTU/H		1.5 PPMVD @	BACT-PSD
MN-0071	FAIRBAULT ENERGY PARK	06/05/07	05/29/08	COMBINED CYCLE COMBUSTION TURBINE GENERATOR WITH 249 MMBTU/H DUCT BURNER. NATURAL GAS AND DISTILLATE OIL FOR FUELS. GE 7FA COMBUSTION TURBINE INSTEAD OF ORIGINALLY PERMITTED MITSUBISHI F CLASS TURBINE.	1758 MMBTU/H		1.5 PPMVD	BACT-PSD
PA-0291	HICKORY RUN ENERGY STATION	04/23/13	05/27/16	Natural gas-fired combined-cycle electric generation facility that is designed to generate up to 900 MW nominal, using 2 combustion turbine generators and 2 heat recovery steam generators that will provide steam to drive a single steam turbine generator. Each heat recovery steam generator will be equipped with a duct burner which may be utilized at time of peak power demands to supplement power output. The project will also include a natural gas-fired auxiliary boiler; a diesel engine-driven emergency generator; a diesel engine-driven firewater pump; a multi-cell evaporative cooling tower; and associated emission control systems, tanks, and other balance of plant equipment.	3.4 MMCF/HR	Oxidation Catalyst	1.5 PPMVD @	OTHER CASE-BY-CASE
*PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	06/15/15	07/12/17	Calpine Mid-Merit, LLC. currently operates Block 1 of the York Energy Center under Title V operating permit 67-05083 with a rated capacity of 565 MW. This plan approval is for the construction and temporary operation of Block 2 Electricity Generation Project having a nominal generating capacity of 835 MW. Block 2 consists of two combined cycle NG/USLD fuel fired combustion turbines, one NG-fired auxiliary boiler, one cooling tower, NG piping components, circuit breaker upgrades, five NG condensate tanks, and additional USLD fuel oil storage tank. Each CT will be limited to 4500 hr/yr with duct firing; 480 hr/yr of USLD	2291.64 MCF/hr	Oxidation catalyst, good combustion practices and low sulfur fuels	1.5 PPMVD @	LAER

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
*PA-0309	LACKAWANNA ENERGY CTR/JESSUP	12/23/15	07/20/17	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3) CT/HRSG sharing one (1) steam turbine. The entire power block is rated at 1,500 MW. Additional equipment includes: - one (1) 2,000 kW diesel-fired emergency generator - one (1) 315 HP diesel-fired emergency fire water pump - one (1) 184.8 MM BTU/hr natural gas fired boiler - one (1) 12 MMBTU/hr natural gas fuel gas heater - two (2) Diesel fuel storage tanks - four (4) lubricating oil tanks - one (1) aqueous ammonia storage tank	3304.3 MMBtu/hr	Oxidation catalyst, combustion controls, exclusive natural gas	1.5 PPM DV @	LAER
*PA-0310	CPV FAIRVIEW ENERGY CENTER	09/02/16	07/31/17	This plan approval authorizes CPV Fairview, LLC to construct and temporarily operate the Fairview Energy Center. Air contamination sources and air cleaning devices authorized for construction and temporary operation under this plan approval include: A combined cycle electric generating unit consisting of two (2) General Electric (&quot;GE&quot;) 7HA.02 &quot;H&quot;-class combustion turbines each with maximum fuel type-based heat input of 3,338-MMBtu/hr (natural gas), 3,274-MMBtu/hr (ULSD), 3,199 MMBtu/hr (ethane blend), and equipped with dry low-NOx combustors and evaporative turbine intake cooling; two (2) heat recovery steam generators (HRSGs) each equipped with a low-NOx duct burner with maximum heat input of 425-MMBtu/hr, and a common steam turbine generator. Exhaust emissions from each combined cycle electric generating unit will be controlled by oxidation catalyst and selective catalytic reduction (SCR). - One (1) up to 12-cell mechanical draft wet cooling tower with high-efficiency drift eliminator. - One (1) natural gas-fired auxiliary boiler with maximum heat input of 92.4 MMBtu/hr. - One (1) natural gas-fired dew point heater with maximum heat input of 12.8 MMBtu/hr. - One (1) natural gas-fired dew point heater with maximum heat input of 3.2 MMBtu/hr. - Two (2) 1,500-ekW diesel-fired emergency genset engines. - One (1) 422-bhp diesel-fired fire water pump engine. - One (1) 1,000,000-gallon ULSD storage tank. - Eight (8) sulfur hexafluoride (SF6) circuit breakers. - Plant roadways.	3338 MMBtu/hr	Oxidation catalyst and good combustion practices	1.5 PPM DV @	LAER

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
*PA-0311	MOXIE FREEDOM GENERATION PLANT	09/01/15	07/31/17	The Project is for the construction and operation of two identical 1 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined- cycle power islands. Each CT and duct burner will exclusively fire pipeline-quality natural gas. The HRSGs will be equipped with selective catalytic reduction (SCR) to minimize nitrogen oxide (NOx) emissions and oxidation catalysts to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions from the CTs and DBâ€™s. The Project will also include several pieces of ancillary equipment. The list of equipment includes: One fuel gas dew-point heater - natural gas fired, common for all CTs Two CT inlet evaporative coolers - one for each CT (not emissions sources) Two air-cooled condensers (ACCs) - one for each HRSG (not emissions sources) One auxiliary boiler, natural gas-fired One diesel engine powered emergency generator One diesel engine powered fire water pump Diesel fuel, lubricating oil, and aqueous ammonia storage tanks The project once operational will produce 1050 MW Electric Generation	3727 MMBtu/hr	Oxidation catalyst and good engineering practice	1.5 PPM DV @	LAER
MD-0042	WILDCAT POINT GENERATION FACILITY	04/08/14	03/16/16	1000 MEGAWATT COMBINED CYCLE NATURAL GAS-FIRED POWER PLANT FACILITY-WIDE PM10 EMISSION LIMIT = 278 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT = 272 TONS/YR FACILITY-WIDE SAM EMISSION LIMIT = 96 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 3,498,026 TONS/YR	1000 MW	USE OF PIPELINE NATURAL GAS, GOOD COMBUSTION PRACTICES, AND USE OF AN OXIDATION CATALYST	1.6 PPM DV @	LAER
*CT-0161	KILLINGLY ENERGY CENTER	06/30/17	08/28/17	550 MW Combined Cycle Plant	2639 MMBtu/hr	Oxidation Catalyst	1.6 PPM DV @	BACT-PSD
GA-0127	PLANT MCDONOUGH COMBINED CYCLE	01/07/08	10/09/08	THREE NATURAL GAS FIRED COMBINED CYCLE POWER BLOCKS. EACH BLOCK CONSISTS OF TWO COMBUSTION TURBINES, TWO HEAT RECOVERY STEAM GENERATORS WITH DUCT BURNERS AND A STEAM TURBINE. TWO TURBINES WILL BE CAPABLE OF FIRING ULTRA LOW SULFUR DIESEL AS BACKUP FUEL. EACH COMBINED-CYCLE BLOCK WILL HAVE OUTPUT OF 840 MW. TURBINES ARE REPLACING TWO COAL-FIRED UTILITY BOILERS	254 MW	OXIDATION CATALYST	1.8 PPM @ 15	LAER
TX-0590	KING POWER STATION	08/05/10	09/14/11	Four combined-cycle natural gas-fired combustion turbines	1350 MW	DLN burners in combination with an oxidation catalyst	1.8 PPM DV AT	LAER
NJ-0074	WEST DEPTFORD ENERGY	05/06/09	01/07/15	A NEW POWER GENERATING FACILITY TO BE BUILT IN WEST DEPTFORD. IT IS A PSD, LAER AND TITLE V FACILITY.	17298 MMFT3/YR	CO OXIDATION CATALYST AND GOOD COMBUSTION PRACTICES	1.9 PPM DV @ 1	LAER
OH-0352	OREGON CLEAN ENERGY CENTER	06/18/13	05/04/16	799 Megawatt Combined Cycle Combustion Turbine Power Plant	51560 MMSCF/rolling 12-MO	oxidation catalyst	1.9 PPM	BACT-PSD
*PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	06/15/15	07/12/17	Calpine Mid-Merit, LLC. currently operates Block 1 of the York Energy Center under Title V operating permit 67-05083 with a rated capacity of 565 MW. This plan approval is for the construction and temporary operation of Block 2 Electricity Generation Project having a nominal generating capacity of 835 MW. Block 2 consists of two combined cycle NG/USLD fuel fired combustion turbines, one NG-fired auxiliary boiler, one cooling tower, NG piping componets, circuit breaker upgrades, five NG condensate tanks, and additional ULSD fuel oil storage tank. Each CT will be limited to 4500 hr/yr with duct firing; 480 hr/yr of ULSD	3001.57 MCF/hr	Oxidation catalyst, good combustion practices and low sulfur fuels	1.9 PPM DV @	LAER

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
CA-1177	OTAY MESA ENERGY CENTER LLC	07/22/09	09/12/11		171.7 MW		2 PPMVD @ 1	OTHER CASE-BY-CASE
CA-1178	APPLIED ENERGY LLC	03/20/09	04/11/11		0	Oxidation catalyst	2 PPM	BACT-PSD
CA-1211	COLUSA GENERATING STATION	03/11/11	01/27/14	660 MW NATURAL GAS FIRED POWER PLANT	172 MW		2 PPMVD	BACT-PSD
GA-0138	LIVE OAKS POWER PLANT	04/08/10	09/10/10	LIVE OAKS POWER PLANT PROPOSED FACILITY WILL OPERATE AS A FULLY DISPATCHABLE ELECTRIC GENERATING FACILITY. THE COMBINED CYCLE SYSTEM WILL UTILIZE TWO COMBUSTION TURBINES AND ONE STEAM TURBINE, CONFIGURED IN A TWO-ON-ONE ARRANGEMENT. THE HEAT CONTENT OF THE EXHAUST GASSES WILL BE RECOVERED BY A HEAT RECOVERY STEAM GENERATOR (HRSG), AND USED TO DRIVE A STEAM TURBINE. DURING PEAK LOADS A DUCT BURNER IN THE HRSG CAN BE FIRED TO AD ADDITIONAL HEAT ENERGY TO THE GAS TURBINE EXHAUST, INCREASING THE PRODUCTION OF STEAM SENT TO THE STEAM TURBINE. THE COMBUSTION TURBINES (CTs) SELECTED ARE SIEMENS MODEL SGT6-5000F. EACH COMBUSTION TURBINE WILL GENERATE 200 MW OF ELECTRIC POWER. THE GROSS ELECTRICAL CAPACITY OF THE COMBINED CYCLE FACILITY FIRING NATURAL GAS WILL THEN BE 600 MW.	600 MW	GOOD COMBUSTION PRACTICES, CATALYTIC OXIDATION	2 PPM @ 15%	BACT-PSD
ID-0018	LANGLEY GULCH POWER PLANT	06/25/10	10/05/10	ONE-ON-ONE COMBINED CYCLE PLANT CONSISTING OF (1) NATURAL GAS-FIRED COMBUSTION TURBINE (CT) AND (1) STEAM TURBINE. THE CT IS EQUIPPED WITH (1) HEAT RECOVERY STEAM GENERATOR (HRSG) AND DUCT BURNER. ANCILLARY EQUIPMENT INCLUDES (1) DIESEL-FIRED EMERGENCY GENERATOR, (1) DIESEL-FIRED FIRE PUMP, (1) WET COOLING TOWER, AND (6) DRY CHEMICAL STORAGE SILOS.	2375.28 MMBTU/H	CATALYTIC OXIDATION (CATOX), DRY LOW NOX (DLN), GOOD COMBUSTION PRACTICES (GCP)	2 PPMVD	BACT-PSD
MD-0041	CPV ST. CHARLES	04/23/14	03/16/16	725 MW COMBINED-CYCLE NATURAL GAS-FIRED POWER PLANT FACILITY-WIDE PM10 EMISSION LIMIT = 96.6 TONS/YR FACILITY-WIDE SAM EMISION LIMIT < 7.0 TONS/YR FACILITY-WIDE PM2.5 (TOTAL) EMISSION LIMIT < 100.0 TONS/YR	725 MW	EXCLUSIVE USE OF NATURAL GAS, AND AN OXIDATION CATALYST	2 PPMVD @	LAER
NJ-0081	PSEG FOSSIL LLC SEWAREN GENERATING STATION	03/07/14	05/02/16	This is a new 625 MW combined cycle project at an existing facility. The project will comprise of two combustion turbines, EITHER GE7FA.05 OR Siemens SGT6 5000F, with two duct burners, two Heat Recovery Steam Generators (HRSG), one steam turbine, one 250 HP fire pump and a 3-cell auxiliary cooling tower. Each turbine will be equipped with Selective Catalytic Reduction System (SCR) for control of NOx emissions and Oxidation Catalyst for control of CO and VOC. The heat input rate of the Siemens turbine will be 2,356 MMBtu/hr(HHV) with a 62.1 duct burner MMBtu/hr(HHV). The heat input rate of each GE turbine will be 2,312 MMBtu/hr(HHV) with a 164.4 duct burner MMBtu/hr(HHV).	33691 MMCF/YR	CO Oxidation Catalyst and good combustion practices and use natural gas only as a clean burning fuel	2 PPMVD @ 1	LAER

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	07/19/16	11/03/16	NEW 633 MEGAWATT (MW) GROSS FACILITY CONSISTING OF 1.ONE GENERAL ELECTRIC (GE) 7HA.02 CCCT NOMINALLY RATED AT 380 MW AT ISO CONDITIONS WITHOUT DUCT FIRING WITH A MAXIMUM HEAT INPUT RATE OF: O 3,462 MMBTU/HR(HHV) AT (0) DEGREES F, 100% LOAD COMBUSTING NATURAL GAS O 3,613 MMBTU/HR(HHV) AT (0) DEGREES F, 100% LOAD COMBUSTING ULSD WHICH WILL BE THE BACKUP FUEL OTHER EQUIPMENT INCLUDES: 2.ONE NATURAL GAS-FIRED DUCT BURNER (MAXIMUM HEAT INPUT OF 599 MMBTU/HR(HHV)) FOR SUPPLEMENTAL FIRING. 3.ONE 97.5 MMBTU/HR(HHV) NATURAL GAS FIRED AUXILIARY BOILER, EQUIPPED WITH LOW NOX BURNERS AND FLUE GAS RECIRCULATION FOR CONTROL OF NOX EMISSIONS; 4.ONE 2.25 MMBTU/HR(HHV), 327 BRAKE HORSEPOWER, ULSD FIRED EMERGENCY FIRE PUMP; 5.ONE 14.4 MMBTU/HR(HHV), APPROXIMATELY 1,500 KW ULSD FIRED EMERGENCY GENERATOR; AND 6.ONE 8-CELL, 124,800 GALLON PER MINUTE (GPM) MECHANICAL INDUCED DRAFT COOLING TOWER.	4000 h/yr	Oxidation Catalyst and good combustion practices	2 PPMVD@1	LAER
OH-0352	OREGON CLEAN ENERGY CENTER	06/18/13	05/04/16	799 Megawatt Combined Cycle Combustion Turbine Power Plant	47917 MMSCF/rolling 12-MO	oxidation catalyst	2 PPM	BACT-PSD
OR-0050	TROUTDALE ENERGY CENTER, LLC	03/05/14	05/05/16	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.	2988 MMBTU/H	Oxidation catalyst; Limit the time in startup or shutdown.	2 PPMVD AT	BACT-PSD
PA-0298	FUTURE POWER PA/GOOD SPRINGS NGCC FACILITY	03/04/14	05/04/16	Natural gas-fired combined-cycle electric generation facility that is designed to generate up to 346 MW nominal, using a combustion turbine generator and a heat recovery steam generator that will provide steam to drive a single steam turbine generator. Each heat recovery steam generator will be equipped with a duct burner which may be utilized at time of peak power demands to supplement power output. The Turbine is rated at 2,267 MMBTU/hr HHV (2,042 MMBTU/hr LHV). The Duct burner is rated at 134.3 MMBTU/hr HHV (120 MMBTU/hr LHV). The proposed project will also include a diesel engine-driven emergency generator; a diesel engine-driven firewater pump; a multi-cell evaporative cooling tower; and associated emission control systems, tanks, and other plant equipment.	2267 MMBTU/H	CO Catalyst	2 PPMVD	BACT-PSD
TX-0546	PATTILLO BRANCH POWER PLANT	06/17/09	11/06/09	1400 MW POWER PLANT. 4 NATURAL GAS FIRED TURBINES PLUS HEAT RECOVERY STEAM GENERATORS (HRSG)	350 MW	OXIDATION CATALYST	2 PPMVD	BACT-PSD
TX-0600	THOMAS C. FERGUSON POWER PLANT	09/01/11	09/14/11	Power Plant. Two natural gas-fired combined cycle turbine generators (GE 7FA) with unfired HRSG	390 MW	Natural gas, good combustion practices and oxidation catalyst	2 PPMVD	BACT-PSD
TX-0618	CHANNEL ENERGY CENTER LLC	10/15/12	01/06/14	Combustion turbine (Siemens 501F)/duct burners (475 MMBtu/hr) with heat recovery steam generator	180 MW	Good combustion	2 PPMVD	BACT-PSD
TX-0619	DEER PARK ENERGY CENTER	09/26/12	09/25/13	The Deer Park Energy Center is a combined cycle cogeneration facility consisting of five Siemens/Westinghouse 501F combustion turbine generators, each with a 725 MMBtu/hr duct burner and heat recovery steam generator.	180 MW	good combustion, use of natural gas	2 PPMVD	BACT-PSD
TX-0620	ES JOSLIN POWER PLANT	09/12/12	09/25/13	Three gas-fired combined cycle turbine generators, including a steam turbine generator, to replace the existing steam boiler/turbine generator.	195 MW	good combustion and natural gas as fuel	2 PPMVD	BACT-PSD
TX-0641	PINECREST ENERGY CENTER	11/12/13	11/21/13	Combinec Cycle Electric Generating Plant	700 MW	oxidation catalyst	2 PPMVD	BACT-PSD

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
TX-0660	FGE TEXAS POWER I AND FGE TEXAS POWER II	03/24/14	06/13/14	Electric Generating Utility	230.7 MW	Oxidation catalyst, good combustion practices	2 PPMVD	BACT-PSD
TX-0678	FREEPORT LNG PRETREATMENT FACILITY	07/16/14	05/09/16	In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNG's existing 42-inch natural gas pipeline route. Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Development's existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNG's existing 42-inch gas pipeline.	87 MW	oxidation catalyst	2 PPMVD	BACT-PSD
TX-0708	LA PALOMA ENERGY CENTER	02/07/13	05/09/16	The proposed project is a new electric power plant, fueled by pipeline quality natural gas. The design of the plant is standard combined cycle (CC) technology.	650 MW	oxidation catalyst	2 PPMVD	BACT-PSD
TX-0709	SAND HILL ENERGY CENTER	09/13/13	05/09/16	GE 7FA Natural Gas-fired Combined Cycle Turbine with DB fired HRSG	173.9 MW		2 PPM	BACT-PSD
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	04/29/14	05/09/16	Tenaska proposes a new electric power plant, using combined cycle gas turbine (CCGT) technology and fueled by pipeline quality natural gas. The proposed permit authorizes two CTs (2x1 CCGT), although the final design selected by Tenaska may only consist of one CT (1x1 CCGT).	274 MW	oxidation catalyst	2 PPMVD	BACT-PSD
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	06/18/15	06/29/15	Eagle is proposing to construct two new combined cycle combustion turbines (CTG) which will generate electric power for sale on the wholesale electric market. The ancillary equipment includes an auxiliary boiler, a firewater pump, an emergency generator, a steam turbine, and various support facilities.	210 MW	Oxidation catalyst	2 PPM	LAER
TX-0767	LON C. HILL POWER STATION	10/02/15	10/06/15	The Lon C. Hill Power Station (LCHP) will include two natural gas-fired combined cycle combustion turbines (CTGs) equipped with dry low NOx burners (DLNs), heat recovery steam generators (HRSG), and natural gas-fired duct burners (DBs). Ancillary equipment includes evaporative coolers or inlet chillers, a single steam turbine (ST), auxiliary boiler, emergency generator, firewater pump, two cooling towers, oil water separator, degreaser, two diesel storage tanks, gasoline storage tank, selective catalytic reduction (SCR) and ammonia (NH3) handling systems including an NH3 storage tank, and two water tanks. The LCHP will be a 2x1 combined cycle power plant consisting of two CTGs, two HRSGs and one ST. The CTGs and ST will be one of two options: two Siemens SCC6-5000 CTGs and a SST6-5000 ST, or two General Electric 7FA CTGs and a D-11 ST.	195 MW	oxidation catalyst	2 PPM	BACT-PSD

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
TX-0773	FGE EAGLE PINES PROJECT	11/04/15	12/22/15	The FGEEP Project will include three natural gas-fired combined cycle (NGCC) power blocks, each block comprised of two gas-fired combustion turbines, two supplemental fired duct burners (DBs) heat recovery steam generators (HRSGs), and one steam turbine. FGEEP selected Alstom GT36 combustion turbines (CTs), each nominally rated at 321 megawatts (MW). Each HRSG is equipped with DBs that will have a maximum design heat input capacity of 799 million British thermal units per hour (MMBtu/hr). The CTs and DBs are fueled with pipeline quality natural gas. Each power block will also have a steam turbine generator designed to produce approximately 502 MW with the additional duct firing. Each of the three blocks will include the following ancillary equipment: one multi-cell condenser/cooling tower, one emergency generator, one firewater pump, two diesel storage tanks, and pressurized aqueous ammonia storage tanks.	321 MW	Oxidation Catalyst	2 PPM	BACT-PSD
TX-0788	NECHES STATION	03/24/16	04/21/16	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.	231 MW	OXIDATION CATALYST	2 PPM	BACT-PSD
TX-0789	DECORDOVA STEAM ELECTRIC STATION	03/08/16	03/11/16	The DeCordova Station will consist of two combustion turbine generators (CTGs) operating in simple cycle or combined cycle modes. The gas turbines will be one of two options: Siemens or General Electric.	231 MW	OXIDATION CATALYST	2 PPM	BACT-PSD
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	02/17/16	04/21/16	Liquefied natural gas (LNG) export terminal	34 MW	OXIDATION CATALYST	2 PPM	BACT-PSD
TX-0819	GAINES COUNTY POWER PLANT	04/28/17	06/12/17	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only applies to the turbines and HRSGs.	227.5 MW	Pipeline quality natural gas; limited hours; good combustion practices	2 PPMVD	BACT-PSD
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	11/21/14	09/30/15	Nominal 549 mW(output) natural gas-fired combined cycle power plant.	2419.61 mmBtu/Hr	Oxidation Catalyst & Good Combustion Practices	2 PPM	BACT-PSD
*PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	02/12/16	07/12/17	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator with supplemental 400MMBtu/hr natural gas fired duct burners. The approximate maximum plant nominal generating capacity is 930-1065 MW. Additional facilities will include 245 MMBtu/hr Auxiliary Boiler, one cooling tower, one diesel-fired emergency generator, and one diesel-fired emergency fire pump engine.		Ox Cat and good combustion practices	2.4 PPMVD@1	LAER
CO-0073	PUEBLO AIRPORT GENERATING STATION	07/22/10	09/12/17	Combustion turbine power plant	799.7 MMBTU/H	Good Combustion Control and Catalytic Oxidation (CatOx)	2.5 PPMVD AT	BACT-PSD
TX-0548	MADISON BELL ENERGY CENTER	08/18/09	11/06/09	THE PROJECT WOULD INCLUDE FOUR NATURAL GAS-FIRED COMBUSTION TURBINES (GE F7EA) AND FOUR HEAT RECOVERY STEAM GENERATORS (HRSGS) WITH PROVISIONS FOR DUCT FIRING. THE PROPOSED PROJECT WILL OPERATE THE COMBUSTION TURBINES IN COMBINED CYCLE MODE. THE COMBINED NOMINAL GENERATING CAPACITY OF THE PLANT IS APPROXIMATELY 550 MW IN COMBINED CYCLE MODE.	275 MW	GOOD COMBUSTION PRACTICES	2.5 PPMVD	BACT-PSD

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	08/28/12	05/29/15	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	40 MW	Oxidation Catalyst	3 PPMV AT 1	BACT-PSD
TX-0819	GAINES COUNTY POWER PLANT	04/28/17	06/12/17	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only applies to the turbines and HRSGs.	426 MW	Oxidation catalyst and good combustion practices	3.5 PPMVD	BACT-PSD
IL-0112	NELSON ENERGY CENTER	12/28/10	03/15/16	Natural gas-fired electric power generation facility with two "combined cycle" turbines followed by heat recovery steam generators (HRSG) and the capability for supplemental fuel firing in the HRSG for each turbine using duct burners. NOx emissions will be controlled by SCR and low NOx combustors.	220 MW each		4 PPMVD @	BACT-PSD
MI-0412	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/04/13	05/05/16	Natural gas combined heat and power plant.	647 MMBTU/H for each CTGHRSG	Oxidation catalyst technology and good combustion practices.	4 PPM	BACT-PSD
*MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	12/05/16	07/31/17	Natural gas combined heat and power plant.	554 MMBTU/H, each	Oxidation catalyst technology and good combustion practices.	4 PPM AT 15	BACT-PSD
*MI-0423	INDECK NILES, LLC	01/04/17	07/25/17	Natural gas combined cycle power plant.	8322 MMBTU/H	Oxidation Catalyst Technology and Good Combustion Practices	4 PPM	BACT-PSD
NY-0098	ATHENS GENERATING PLANT	01/19/07	08/12/08	NATURAL GAS FIRED COMBINED CYCLE FACILITY RATED AT 1080 MW. THE FACILITY CONSISTS OF 3 WESTINGHOUSE MODEL 501G GAS TURBINES (245 MW BASE LOAD), HEAT RECOVERY STEAM GENERATORS, AND STEAM TURBINE GENERATORS (115 MW) WITH SELECTIVE CATALYTIC REDUCTION (SCR) FOR NOX EMISSION CONTROL. THE ALTERNATE FUEL IS DISTILLATE FUEL OIL WITH A LIMIT OF 1080 HRS/YR FOR EACH TURBINE. THE FACILITY HAS A 4 MILLION GALLON DISTILLATE OIL TANK, THREE AQUEOUS AMMONIA TANKS (20,000 GALLONS EACH) AND AN EMERGENCY DIESEL GENERATOR AND DIESEL FIRE PUMP.	3100 MMBTU/H	GOOD COMBUSTION CONTROL	4 PPMVD @	LAER
TX-0547	NATURAL GAS-FIRED POWER GENERATION FACILITY	06/22/09	11/06/09	THE NEW POWER BLOCK WILL BE CAPABLE OF PRODUCING EITHER 620 OR 910 MEGAWATTS OF ELECTRICITY, DEPENDING UPON WHICH COMBUSTION TURBINE MODEL OPTION IS CHOSEN.	250 MW	GOOD COMBUSTION PRACTICES	4 PPMVD	BACT-PSD
TX-0710	VICTORIA POWER STATION	12/01/14	05/09/16	The facility is currently authorized under Standard Permit No. 80878 and several Permits by Rule (PBR), including 106.263 for maintenance, startup, and shutdown (MSS) (PBR Registration No. 94387) and Title V Permit No. O-35. Victoria proposes to install an additional natural gas-fired turbine (GT) and HRSG with duct burners at the Victoria Station. The resulting new facility will be a combined cycle generating facility in a 2x2x1 configuration (two combustion turbines, two HRSGs with duct burners, and one steam turbine).	197 MW	oxidation catalyst	4 PPMVD	BACT-PSD
TX-0712	TRINIDAD GENERATING FACILITY	11/20/14	05/09/16	Southern Power Company (SPC) is proposing to construct an electric generating facility near Trinidad, Henderson County, Texas. The Trinidad Generating Facility (TGF) will include a natural gas-fired combined cycle combustion turbine generator (CTG) equipped with heat recovery steam generator (HRSG) and duct burners (DB).	497 MW	oxidation catalyst	4 PPMVD	BACT-PSD

Table D-1. VOC Determinations for Large CTs (> 25 MW) combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
TX-0730	COLORADO BEND ENERGY CENTER	04/01/15	05/16/16	Combined cycle combustion turbine electric generating facility. These will be the first two General Electric (GE) Model 7HA.02 Combustion Turbines in a combined cycle power plant that uses two combustion turbines and one steam turbine using air-cooled condensers and controlled with Selective catalytic reduction (SCR) and oxidation catalyst.	1100 MW	SCR and oxidation catalyst	4 PPMVD @	BACT-PSD
CO-0073	PUEBLO AIRPORT GENERATING STATION	07/22/10	03/10/16	Combustion turbine power plant	373 MMBTU/H	good combustion control and catalytic oxidation	4 PPMVD AT	BACT-PSD
MN-0066	NORTHERN STATES POWER CO. DBA XCEL ENERGY - RIVERSIDE PLANT	05/16/06	10/02/06	POWER PLANT. EXISTING COAL-FIRED BOILERS REPLACED BY NATURAL GAS FIRED F-CLASS COMBUSTION TURBINES AND HRSG, AND NATURAL GAS FIRED AUXILIARY BOILER	1885 mmbtu/h	GOOD COMBUSTION PRACTICES	4.6 PPMVD 15	BACT-PSD
LA-0224	ARSENAL HILL POWER PLANT	03/20/08	05/18/12	NATURAL GAS FIRED ELECTRICAL GENERATION PLANT.	2110 MMBTU/H	PROPER OPERATING PRACTICES	4.9 PPMVD @1	BACT-PSD
CT-0151	KLEEN ENERGY SYSTEMS, LLC	02/25/08	04/10/12	580 MW NOMINAL (620 MW PEAK) BASE LOAD NATURAL GAS FIRED POWER PLANT WITH NO.2 OIL BACKUP. TWO SIEMENS SGT6-5000F COMBUSTION TURBINE TRAINS WITH HRSG AND NATURAL GAS DUCT BURNER.	2.1 MMCF/H	SOME REDUCTIONS OF VOC ARE GAINED FROM CO CATALYST BUT ARE NOT GUARANTEED. EMISSION RATES DO NOT INCORPORATE THIS POTENTIAL REDUCTION.	5 PPMVD @	BACT-PSD
OK-0154	MOORELAND GENERATING STA	07/02/13	04/15/16	WFEC operates the Mooreland Generating Station to generate wholesale electricity which is transmitted over WFEC's system. The facility was originally constructed in 1963. The electricity is sold in rural areas of approximately 3/4 of the state of Oklahoma and part of New Mexico. The Mooreland Generating Station currently consists of three high-pressure boilers that burn locally-produced natural gas. The three high-pressure boilers used to generate electricity and the auxiliary boiler used to heat the facility were constructed before May 31, 1972, and are considered grandfathered from construction permitting requirements.	360 MW	Oxidation catalyst and good combustion practices.	5 PPMVD @1	BACT-PSD

Note: All information in this table is exactly as it appears in EPA's RBLC database.

Source: EPA RBLC, queried October 18, 2017.

Table D-2. VOC Determinations for Fuel Gas Heaters combusting Natural Gas

RBLC ID	Facility Name	Issue Date		Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
		Issuance	Update					
FL-0286	FPL WEST COUNTY ENERGY CENTER	01/10/07	03/03/09	DEW POINT HEATER	5 MMBTU/H	USE OF EFFICIENT DESIGN OF THE HEATER, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS ONLY, AND APPLICATION OF GOOD COMBUSTION PRACTICES	0.005 LB/MMBTU	LAER
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	07/30/08	01/05/11	Fuel Gas Heater			0.005 LB/MMBTU	LAER
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	07/30/08	01/05/11	FUEL GAS HEATER	9.5 MMBTU/H	EXCLUSIVE USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.005 LB/MMBTU	LAER
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	07/30/08	01/05/11	FUEL GAS HEATER	13.8 MMBTU/H	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0054 LB/MMBTU	LAER
FL-0286	FPL WEST COUNTY ENERGY CENTER	01/10/07	03/03/09	DEW POINT HEATER	15 MMBTU/H		0.006 LB/MMBTU	OTHER CASE-BY-CASE
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	03/09/16	07/06/16	FG-FUELHTRS: 2 natural gas fuel heaters, 12 MMBTU/H each	12 MMBTU/H heat input each fuel heater	Efficient combustion; natural gas fuel.	0.008 LB/MMBTU	BACT-PSD
FL-0286	FPL WEST COUNTY ENERGY CENTER	01/10/07	03/03/09	EUFUELHTR (Fuel pre-heater)	3.7 MMBTU/H	Good combustion practices.	0.03 LB/H	BACT-PSD
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	07/30/08	01/05/11	Fuel pre-heater (EUFUELHTR)	3.7 MMBTU/H	Good combustion practices	0.03 LB/H	BACT-PSD
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	07/30/08	01/05/11	Fuel Preheater	8.5 MMBTU/H		0.05 LB/MMBTU	OTHER CASE-BY-CASE
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	07/30/08	01/05/11	FUEL GAS HEATER (H2O BATH)	18.8 MMBTU/H		0.1 LB/H	BACT-PSD
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	03/09/16	07/06/16	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	27 MMBTU/H	Good combustion practices.	0.15 LB/H	BACT-PSD
CA-1211	COLUSA GENERATING STATION	03/11/11	01/27/14	TWO GAS-FUELED 10 MMBTU/H PROCESS HEATERS	10 MMBTU/H		2 GR S/100 SCF GAS	BACT-PSD
CA-1211	COLUSA GENERATING STATION	03/11/11	01/27/14	TWO NOMINAL 10 MMBTU/H NATURAL GAS-FIRED PROCESS HEATERS	10 MMBTU/H		2 GS/100 SCF	BACT-PSD
CA-1211	COLUSA GENERATING STATION	03/11/11	01/27/14	WATER BATH HEATER	10 MMBTU/H		7 PPMVD	BACT-PSD

Note: All information in this table is exactly as it appears in EPA's RBLC database.

Source: EPA RBLC, queried October 18, 2017.

Appendix E

Precautions to Prevent Emissions of Unconfined Particulate Matter

Appendix E—SGS SCCF Precautions to Prevent Emissions of Unconfined Particulate Matter

Unconfined particulate matter emissions may result from operations including:

- Vehicular traffic on paved and unpaved roads and parking areas.
- Wind-blown dust from paved and unpaved roads and parking areas.

The following techniques will be used to prevent unconfined particulate matter emissions on an as needed basis:

- Chemical or water application to:
 - o Unpaved roads and parking areas.
 - o Unpaved yard areas.
- Flushing/sweeping paved roads and parking areas.
- Landscaping or planting of vegetation.
- Other techniques, as necessary.

Appendix F

Acid Rain Part Application Form

Acid Rain Part Application

For more information, see instructions and refer to 40 CFR 72.30, 72.31, and 74; and Chapter 62-214, F.A.C.

This submission is: ☐ New ☐ Revised ☒ Renewal

STEP 1

Identify the source by plant name, state, and ORIS or plant code.

Plant name	State	ORIS/Plant Code
Seminole Generating Station	Florida	136

STEP 2

Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a."

If unit a SO₂ Opt-in unit, enter "yes" in column "b".

For new units or SO₂ Opt-in units, enter the requested information in columns "d" and "e."

a	b	c	d	e
Unit ID#	SO ₂ Opt-in Unit? (Yes or No)	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	New or SO ₂ Opt-in Units Commence Operation Date	New or SO ₂ Opt-in Units Monitor Certification Deadline
001	No	Yes	Not applicable	Not applicable
002	No	Yes	Not applicable	Not applicable
009	No	Yes	Not applicable	Not applicable
010	No	Yes	Not applicable	Not applicable
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		

Plant Name (from STEP 1)

Seminole Generating Station

STEP 3

Read the standard requirements.

Acid Rain Part Requirements.

- (1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
 - (i) Submit a complete Acid Rain Part application (including a compliance plan) under 40 CFR Part 72 and Rules 62-214.320 and 330, F.A.C., in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
 - (ii) Submit in a timely manner any supplemental information that the DEP determines is necessary in order to review an Acid Rain Part application and issue or deny an Acid Rain Part;
- (2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
 - (i) Operate the unit in compliance with a complete Acid Rain Part application or a superseding Acid Rain Part issued by the DEP; and
 - (ii) Have an Acid Rain Part.

Monitoring Requirements.

- (1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75, and Rule 62-214.420, F.A.C.
- (2) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
- (3) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.
- (4) For applications including a SO₂ Opt-in unit, a monitoring plan for each SO₂ Opt-in unit must be submitted with this application pursuant to 40 CFR 74.14(a). For renewal applications for SO₂ Opt-in units include an updated monitoring plan if applicable under 40 CFR 75.53(b).

Sulfur Dioxide Requirements.

- (1) The owners and operators of each source and each Acid Rain unit at the source shall:
 - (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
 - (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
- (2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
- (3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
 - (i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
 - (ii) Starting on the later of January 1, 2000, or the deadline for monitor certification under 40 CFR Part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
- (4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
- (5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
- (6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain Part application, the Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
- (7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

- (1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77.
- (2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
 - (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and
 - (ii) Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

Recordkeeping and Reporting Requirements.

- (1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the DEP:
 - (i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
 - (ii) All emissions monitoring information, in accordance with 40 CFR Part 75, provided that to the extent that 40 CFR Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
 - (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Plant Name (from STEP 1)

Seminole Generating Station

**STEP 3,
Continued.**

Recordkeeping and Reporting Requirements (cont)

(iv) Copies of all documents used to complete an Acid Rain Part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72, Subpart I, and 40 CFR Part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.

(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.

(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.

(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.

(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.

(7) Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities.

No provision of the Acid Rain Program, an Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established.

STEP 4

For SO₂ Opt-in units only.

In column "f" enter the unit ID# for every SO₂ Opt-in unit identified in column "a" of STEP 2.

For column "g" describe the combustion unit and attach information and diagrams on the combustion unit's configuration.

In column "h" enter the hours.

f	g	h (not required for renewal application)
Unit ID#	Description of the combustion unit	Number of hours unit operated in the six months preceding initial application

Plant Name (from STEP 1)

Seminole Generating Station

STEP 5

For SO₂ Opt-in units only.
(Not required for SO₂ Opt-in renewal applications.)

In column "i" enter the unit ID# for every SO₂ Opt-in unit identified in column "a" (and in column "f").

For columns "j" through "n," enter the information required under 40 CFR 74.20-74.25 and attach all supporting documentation required by 40 CFR 74.20-74.25.

i	j	k	l	m	n
Unit ID#	Baseline or Alternative Baseline under 40 CFR 74.20 (mmBtu)	Actual SO ₂ Emissions Rate under 40 CFR 74.22 (lbs/mmBtu)	Allowable 1985 SO ₂ Emissions Rate under 40 CFR 74.23 (lbs/mmBtu)	Current Allowable SO ₂ Emissions Rate under 40 CFR 74.24 (lbs/mmBtu)	Current Promulgated SO ₂ Emissions Rate under 40 CFR 74.25 (lbs/mmBtu)

STEP 6

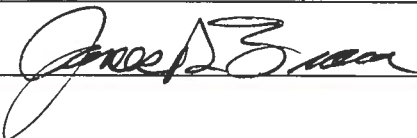
For SO₂ Opt-in units only.

Attach additional requirements, certify and sign.

- If the combustion source seeks to qualify for a transfer of allowances from the replacement of thermal energy, a thermal energy plan as provided in 40 CFR 74.47 for combustion sources must be attached.
- A statement whether the combustion unit was previously an affected unit under 40 CFR 74.
- A statement that the combustion unit is not an affected unit under 40 CFR 72.6 and does not have an exemption under 40 CFR 72.7, 72.8, or 72.14.
- Attach a complete compliance plan for SO₂ under 40 CFR 72.40.
- The designated representative of the combustion unit shall submit a monitoring plan in accordance with 40 CFR 74.61. For renewal application, submit an updated monitoring plan if applicable under 40 CFR 75.53(b).
- The following statement must be signed by the designated representative or alternate designated representative of the combustion source: "I certify that the data submitted under 40 CFR Part 74, Subpart C, reflects actual operations of the combustion source and has not been adjusted in any way."

STEP 7

Read the certification statement; provide name, title, owner company name, phone, and e-mail address; sign, and date.

Signature		Date	
Certification (for designated representative or alternate designated representative only)			
I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.			
Name James R. Frauen		Title Vice President, Power Delivery and Technical	
Owner Company Name Seminole Electric Cooperative, Inc.			
Phone (813) 739-1213		E-mail address jffrauen@seminole-electric.com	
Signature 		Date 12-7-17	

Appendix 10.2.6

Air Operation Permit

10.2.6 Air Operation Permit

As required under Section 62-213.420, Florida Administrative Code (F.A.C.), the application for revision of the existing Title V air operation permit for the Seminole Generating Station (SGS) to include the Seminole Combined-Cycle Facility (SCCF) will be submitted to the Florida Department of Environmental Protection (FDEP) within 180 days after the Project commences operation.

Appendix 10.6.4 of this site certification application provides a copy of the existing SGS Title V Air Operation Permit No. 1070025-027-AV.

Appendix 10.2.7

Coastal Zone Management Certifications

10.2.7 Coastal Zone Management Certifications

Electrical power plants are subject to the federal coastal consistency review program under Section 380.23, F.S. Pursuant to Section 403.511(7), F.S., issuance of the final site certification under the PPSA constitutes the state's certification of coastal zone consistency.