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David B. Struhs
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December 21, 1999

Mr. R. Douglas Neeley, Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics Management Division
United States Environmental Protection Agency
Region 4
61 Forsyth Street, SW
Atlanta, GA 30303-8909

Re: Proposed Changes to Satisfy EPA Objections
Florida Power Corporation, Crystal River Plant, PROPOSED Title V Permit 0170004-004-AV

Dear Mr. Neeley:

This letter is to document changes that the Department proposes to satisfy EPA Region 4 objections to Florida's PROPOSED Title V permit 0170004-004-AV for Florida Power Corporation, Crystal River Plant. These objections were detailed in a letter from EPA Region 4 dated November 1, 1999, in which EPA indicated the primary basis for objection is that the permit does not assure compliance with all applicable requirements as required by 40 C.F.R. 70.1(b) and 40 C.F.R. 70.6(a)(1). Specifically, the permit does not contain terms or conditions assuring compliance with Prevention of Significant Deterioration requirements applicable to this facility under the Clean Air Act, the Florida State Implementation Plan, and 40 C.F.R. part 70. In addition, the permit does not fully meet the periodic monitoring requirements of 40 C.F.R. 70.6(a)(3)(i), and the permit does not assure compliance with the requirements of 40 C.F.R. 70.6(a)(1).

The changes proposed in this letter result primarily from a letter from Mr. W. Jeffrey Pardue, the Responsible Official for the Crystal River Plant, and the past resolution to similar objections the EPA found acceptable. Hopefully these changes will allow Florida to issue the FINAL Title V permit for this plant. Please review the following proposed changes to the referenced permit. If you concur with our changes, we will issue the FINAL Title V permit with these changes.

I. EPA Objection Issues

1. Applicable Requirements - Based on our review of the proposed permit, the title V permit application, and supplemental materials, EPA has determined that the proposed permit for the FPC Crystal River facility does not assure compliance with all applicable requirements under the Clean Air Act (CAA or the Act), the Florida State Implementation Plan (SIP), and state and federal title V regulations. Specifically, the permit does not contain terms and conditions assuring compliance with applicable Prevention of Significant Deterioration (PSD) requirements of the Act, the Florida SIP, and 40 C.F.R. part 70 for a proposed major modification to allow the facility to burn petroleum coke ("petcoke").

Pursuant to CAA § 504(a), title V permits are to include, among other conditions, "enforceable emission limitations and standards, . . . and such other conditions as are necessary to assure compliance with applicable requirements of [the Act], including the requirements of the applicable implementation plan." "Applicable requirements" are defined in 40 C.F.R. § 70.2 to include: "(1) any standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the Act...". As you know, FDEP defines "applicable requirement" in a similar fashion to include, among other requirements, "any standard or other requirement provided for in the state implementation plan" 62-210.200(31)(a)(1) Florida Administrative Code (F.A.C.).

Applicable requirements include the requirement to obtain preconstruction permits that comply with applicable preconstruction review requirements under the Clean Air Act, EPA regulations, and SIPs. See generally CAA §§ 110(a)(2)(C), 160-69, & 173; 40 C.F.R. §§ 51.160-66 & 52.21; see also Order In re Roosevelt Regional Landfill, at 2, 8 (May 4, 1999); Order In re Monroe Electric Generating Plant Entergy Louisiana, Inc., at 2 (June 11, 1999). Such applicable requirements include the requirement to obtain a PSD permit that in turn complies with applicable PSD requirements. See CAA § 165; 40 C.F.R. §§ 51.160, 51.166 & 52.21; 48 FR 52,713 (November 22, 1983); Rule 62-212.400 F.A.C. Those requirements include, but are not limited to: the use of best available control technology (BACT) for each regulated pollutant that would be emitted in significant amounts, at each emissions unit at which the increase would occur; associated emission limitations; and any additional requirements resulting from the PSD review, such as those that are necessary to afford protection to any Class I area air quality related values.

The *FPC Crystal River Facility Title V Air Operating Permit Application*, signed June 12, 1996, indicates that on December 26, 1995, FPC submitted to FDEP a request to allow the Crystal River facility to burn a blend of petroleum coke and coal in Units 1 & 2. This proposed modification would result in an actual emissions increase of approximately 9,400 tons per year of sulfur dioxide and a corresponding increase in the potential emissions of sulfur dioxide of approximately 18,700 tons per year. There are no scrubbers present or planned for Units 1 & 2 to abate this emissions increase.

As you are aware, a major source is subject to PSD requirements if the proposed modification will result in a significant net emissions increase of 40 tons or more per year of sulfur dioxide. See 40 C.F.R. §§ 51.166(b)(2), 51.166(b)(23) & 51.166(i); see also 62-212.400(2)(e)2 F.A.C. Hence, it is our determination that the proposed modification is a major modification subject to PSD review.

FPC's application, however, did not address PSD requirements, because FPC contended that it qualified for an exemption from PSD permitting requirements under Rule 62-212.400(2)(c)4 F.A.C. This FDEP rule, as well as federal PSD requirements at 40 C.F.R. § 51.166(b)(2)(iii)*(e)(1)*, exclude from the definition of major modification the use of an alternative fuel or raw material which:

the source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975. . . .

We are aware that after reviewing FPC's application to burn petcoke, FDEP originally issued an Intent to Deny the permit on June 25, 1996. Following an administrative hearing and a series of procedural events, FDEP issued a Final Order denying the permit on March 2, 1998. FPC appealed this decision to the Fifth District Court of Appeal of Florida (5th DCA). However, following negotiations with FPC, FDEP agreed to vacate the Final Order and joined with FPC in filing a Joint Motion for Relinquishment of Jurisdiction with the 5th DCA. On January 11, 1999, FDEP granted FPC a final state construction permit to authorize the burning of a petcoke-coal blend in Units 1 and 2. This permit was not issued pursuant to the State PSD regulations, and hence, does not meet the requirements of the CAA, Federal PSD Regulations or the Florida SIP. In addition, this permit was issued without an opportunity for public or EPA review. The proposed title V permit is, thus, the first opportunity for EPA to comment on the permit conditions related to the proposed modification. It is our understanding that the facility has not commenced burning of petcoke.

EPA has reviewed the supporting information related to the above proceedings, including, but not limited to: supplemental information submitted by FPC to EPA on January 6, 1997, February 11, 1997, February 18, 1997, February 21, 1997, February 28, 1997, and May 21, 1997; information submitted by FDEP to EPA on December 24, 1996 and May 13, 1997; the Recommended Order of the administrative law judge (ALJ) following the FDEP's administrative hearing (September 23, 1977); the FDEP's Final Order to Deny the permit (March 2, 1998); and the subsequent vacature of that order (January 4, 1999). As communicated in our letters to Howard L. Rhodes, dated June 2, 1997 and July 30, 1997, and for the reasons outlined below, EPA continues to maintain that the exemption for alternative fuels given in 40 C.F.R. § 51.166(b)(2)(iii)*(e)(1)* and as incorporated into the SIP at 62-212.400(2)(c)4 F.A.C., is not applicable for the purpose of the proposed petroleum coke modification, and thus, the proposed modification is major modification subject to PSD review.

1. The facility was not capable of accommodating petroleum coke as of January 6, 1975

The administrative hearing record and other supporting information submitted by FPC and FDEP, including discussion of a facility inspection by FDEP on December 16, 1996, indicate that Unit 2 was physically unable to burn solid fuel as of January 6, 1975. Only through substantial modifications made during the late 1970's to reconvert Units 1 and 2 to coal-fired facilities, did Unit 2 regain the ability to burn coal. The record is unclear as to whether the Unit 1 boiler remained capable of burning coal during the time that it burned fuel oil. However, during the "reconversion" process, modifications to Unit 1 included replacement of most of the waterwall, addition of induced draft fans, replacement of pollution control equipment, and addition of railroad tracks to the area. According to the hearing witness for FDEP, the physical alterations were required to make the units capable of accommodating coal. Further, it is not clear that the blending capability to co-fire coal and petcoke was present prior to 1975.

Some of the physical modifications, as documented by FPC, necessary to convert the units back to coal include changes or additions of coal burners; piping for sootblowers, service air, flame scanners, drip drain vents, precipitators, ash water, pyrites, and fluidizing air; coal transport piping, pulverizers and motors; coal feeders; ignitor horns, soot blowers, and flame scanner systems; bottom ash hopper and clinker grinders; ash pond, ash sluice system, and flyash removal system, etc. These modifications were documented to cost over 17 million dollars (past value), and it appears that many of these modifications were necessary to convert the facilities to coal-fired units, rather than to simply bring the units into compliance while burning coal, as characterized by FPC (Letter to Mr. Brian Beals, EPA, December 24, 1996).

As discussed in FDEP's Final Order of March 2, 1997, the ALJ's determination in this matter was flawed and in fact contradictory. Based upon EPA's review of the record, we concur with FDEP's finding in this Order that there was no substantiated evidence to support the assertion that the facility remained capable of co-firing petcoke during the 1970's when the facility fired fuel oil. In fact, the evidence, as well as the ALJ's findings themselves, support the contrary determination that the facility was "converted" from firing liquid fuel to firing solid fuel during the late 1970's, well after the 1975 date in the exemption invoked by FPC.

2. The use of petroleum coke was not designed and built into Units 1 and 2

The alternative fuels exemption is not contained in the Act, but was added to the PSD regulations in 1974 (the current version being codified in 1978) such that the definition of modification would be consistent with that used under the New Source Performance Standards (NSPS), as intended by Section 169(2)(C) of the Act. The stated intent of the NSPS exemption was to "eliminate inequities where equipment had been put into partial operation prior to the proposal of the standards," 36 FR 15,704 (August 3, 1971). The current NSPS regulations, at 40 C.F.R. § 60.14(e)(4), contain an analogue to the PSD alternatives fuel exemption at 40 C.F.R. §52.21(b)(2)(ii)(e), which provides that the use of an alternative fuel or raw material shall not be considered a modification if:

. . . the existing facility was designed to accommodate the alternative use. A facility shall be considered to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. . .

While the original NSPS exemption was changed slightly to allow for changes to the "original" design specification (40 FR 58,416 (December 16,1975)), the alterations did not change the intent of the exemption --- to grandfather voluntary fuel switches that a facility had designed for and built into its system prior to January 6, 1975.

The only fuels contemplated in the design and construction of Units 1 And 2 were coal and oil. Nothing in the design or construction documents for Units 1 and 2 suggests that FPC considered petcoke as a fuel for these units, nor does anything in those documents suggest that the design or construction was intended to accommodate the potential use of petcoke as a fuel. For example, the facility's 1971 operating permit application for Unit 2 required the source to identify "fuels" by type, and required that such identification "be specific." FPC identified only coal as the fuel type in this document and all other pre-1975 documents made available to EPA.

As discussed above, the purpose of the alternative fuels exemption was to eliminate any inequity faced by utilities which designed and constructed units to burn more than one fuel, but which were not burning all of those fuels as of January 6, 1975. For example, absent the exemption, a facility equipped to burn coal and oil, but which was only burning oil at the time the NSPS were adopted, would be subject to the NSPS and subsequently PSD review merely by switching back to coal. Therefore, EPA believes it is reasonable to interpret the alternative fuels exemption to apply only to fuels which were contemplated in the design and construction of a unit prior to January 6, 1975 and which the unit remained continuously able to burn. Units 1 and 2 do not meet these criteria, as they were never designed for petcoke and, through conversion to oil, lost the ability to burn solid fuel prior to January 6, 1975. Furthermore, in the burning of petcoke, FPC does not face the inequity remedied by the alternative fuels exemption.

To interpret this provision as allowing a facility to use "any" fuel that it could possibly burn prior to January 6, 1997, regardless of whether such fuels were originally contemplated or included in the original design, improperly expands the availability of the intended PSD exemption. To do so would also establish an obvious inequity, neither intended nor likely to be overlooked by EPA in crafting the exemption, whereby facilities constructed prior to 1975 would be able to burn any number of fuels without complying with PSD or NSPS requirements and those constructed after this date would be subject to review and substantive requirements.

3. The proposed petroleum coke-coal fuel blend is not an "alternative fuel" within the meaning of the exemption.

As discussed in Alabama Power Co. v. Costle, the PSD exemption at 40 C.F.R. §52.21(b)(2)(iii)(e) and the corresponding Florida provision at 62-212.400(2)(c)4 F.A.C. were intended to grandfather "voluntary fuel switches by emission sources which were designed to accommodate the alternative fuels prior to January 6, 1975." The provision was not intended to provide a loop-hole by which facilities may add various substances, such as waste products or waste fuels, to their primary fuels without being subject to PSD review. The Federal Register notices and background information documents that speak to this particular exemption only reference primary fuels, such as coal, oil and gas. At the time the alternative fuel exemption was promulgated, EPA contemplated "switches" between primary fuels. Therefore, it is a reasonable interpretation of the regulations to limit this exemption to primary fuels and not to apply the exemption to fuel additives that the facility was neither designed nor built to use as a primary fuel. FPC is currently burning coal as their primary fuel. It is EPA's determination that burning a 95% coal, 5% petcoke blend does not constitute a "switch" to an "alternative" fuel as intended by the exemption. Rather, the blending in of 5% petcoke is a change in the current method of operation that is subject to PSD review.

The above interpretations are consistent with FDEP's and EPA's longstanding interpretations of the "capable of accommodating" exemption. As you are aware, there are several EPA guidance memoranda, including a June 7, 1983 document from this office to Mr. Steve Smallwood of FDEP, that interpret the exemption to require that the facility be "designed" and continuously able to accommodate the use of a specified alternative fuel. This guidance clearly states:

In order for a plant to be capable of accommodating coal, the company must show not only that the design (i.e., construction specifications) for the source contemplated the equipment, but also that the equipment actually was installed and still remains in existence. Otherwise, it cannot reasonably be concluded that the use of coal was "designed into the source."

FDEP's past implementation of its new source review regulations has also been consistent with this interpretation. According to FDEP's December 24, 1996 letter from C. H. Fancy, Bureau of Air Regulation, to Mr. Brian Beals, EPA, requesting assistance with the FPC PSD applicability determination, FDEP had treated as major modifications, the use of a petroleum coke-coal blend in five coal-fired units in Florida for the purposes of PSD permitting as of that date. As documented in FDEP's letter: "in each case, the proposals have been treated as changes in method of operation to which PSD is applicable unless they are able to 'net out' by demonstrating that there will be no significant increases in PSD pollutants."

To remedy the above identified deficiency, the title V permit must include a compliance schedule, consistent with 40 C.F.R. §70.5(c)(8)(iii), that requires FPC to obtain a PSD permit fulfilling State and federal PSD requirements and 40 C.F.R. §70.6(c)(3). Progress reports referenced under 40 C.F.R. §70.6(c)(4) must be required by the permit. Any additional requirements resulting from the PSD review, including requirements for control equipment and emission limitations, will have to be incorporated into the title V permit through permit modification. Alternatively, the State may concurrently issue proposed PSD and title V permits. As a third option, the State could issue a valid synthetic minor permit, limiting the emissions increase from the proposed change to less than the applicable PSD significance levels. As above, such conditions would need to be incorporated into the title V permit.

PERMITTEE RESPONSE: Response - On pages 1 through 7 of its objection, EPA in essence expresses disagreement with a DEP Final Order concluding that co-firing petroleum coke with coal at Crystal River Units 1 and 2 is exempt from PSD applicability. <u>This issue is now moot because FPC has determined that it no longer wishes to burn petroleum coke in Units 1 and 2.</u> Accordingly, FPC does not object to deletion of petroleum coke as an authorized fuel under the Title V permit.

It should be understood that FPC's decision not to co-fire petroleum coke with coal is unrelated to the merits of EPA's objection and does not constitute agreement with EPA, or legal precedent. During the petroleum coke permitting process, FPC representatives mentioned to DEP personnel on several occasions that its utilization of petroleum coke in Units 1 and 2 might be abandoned by the year 2000.

The basis for FPC's substantive disagreement with EPA's objection is set forth in the record on appeal and briefs in Case No. 98-858 (District Court of Appeal, Fifth District), as well as the January 4, 1999 DEP Final

Order on Remand (all on file at DEP). These materials verify that the factual and legal analysis in EPA's November 1, 1999 objection is incorrect. Moreover, it is not appropriate for EPA to employ the Title V process as a means to second guess DEP's Final Order on Remand. EPA itself has stated:

> EPA may not intrude upon the significant discretion granted to states under new source review programs, and will not "second guess" state decisions.

63 Federal Register 13797 (March 23, 1998). EPA has acknowledged "that states have the primary role in administering and enforcing the various components of the NSR program." 55 Federal Register 23548 (June 11, 1990). EPA confirmed in 1990 that it "did not intend to suggest" that states are "required to follow EPA's interpretations and guidance issued under the Clean Air Act in the sense that those pronouncements have independent status as enforceable provisions..." Id.

Again, these issues are moot due to FPC's decision not to co-fire petroleum coke at Crystal River Units 1 and 2.

PROPOSED CHANGE: The permit and the Statement of Basis will be changed as follows:

FROM:
Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions units.

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1: a tangentially fired unit, rated at 440.5 MW, 3750 MMBtu/hr, burning bituminous coal; a bituminous coal and bituminous coal briquette mixture; or a bituminous coal and petcoke blend. Distillate fuel oil may be burned as a startup fuel. Emissions are exhausted through a 499 ft. stack.. This unit may also burn oily flyash.
002	Fossil Fuel Steam Generator, Unit 2: a tangentially fired unit, rated at 523.8 MW, 4795 MMBtu/hr, burning bituminous coal; a bituminous coal and bituminous coal briquette mixture; or a bituminous coal and petcoke blend. Distillate fuel oil may be burned as a startup fuel. Emissions are exhausted through a 502 ft. stack. This unit may also burn oily flyash.

Fossil Fuel Steam Generators, Units 1 and 2, are pulverized coal dry bottom boilers, tangentially-fired. Emissions are controlled from each unit with a high efficiency electrostatic precipitator, manufactured by Buell Manufacturing Company, Inc.

A.1. Permitted Capacity. The maximum operation heat input rates are as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
001	3750	Bituminous Coal; Bituminous Coal and Bituminous Coal Briquette Mixture; or bituminous Coal and Petcoke Blend
002	4795	Bituminous Coal; Bituminous Coal and Bituminous Coal Briquette Mixture; or bituminous Coal and Petcoke Blend

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.]

A.3. Methods of Operation. Fuels. The only fuels allowed to be burned by this permit are: bituminous coal; a bituminous coal and bituminous coal briquette mixture, a five percent (plus or minus two percent) blend of petroleum coke with coal by weight, and distillate fuel oil for startup.. These emissions units may also burn used oil in accordance with other conditions of this permit (see **Subsection K**). Emissions units 001 and 002 may also burn oily flyash in accordance with specific condition **A.16** of this permit.
[Rule 62-213.410, F.A.C.; 0170004-002-AO, 0170004-005-AO, 0170004-003-AC and 0170004-006-AC]

A.8. Sulfur Dioxide.
(a) When burning coal or coal blended with petcoke, sulfur dioxide emissions shall not exceed 2.1 pounds per million Btu heat input, 24-hour average.
(b) The maximum sulfur dioxide emissions from the coal/briquette mixture shipment, averaged on an annual basis, shall not exceed the following:

Emissions Unit No.	**Emissions Unit Description**	**Average Sulfur Dioxide Limit, in Pounds Per Million Btu, Heat Input**
001	FFSG, Unit 1	1.67
002	FFSG, Unit 2	1.67

[Rule 62-213.440, F.A.C.; PPSC PA 77-09; 0170004-003-AC; and, 0170004-006-AC]

Statement of Basis:

FFSG Units 1 and 2 are pulverized coal dry bottom boilers, tangentially-fired. Emissions are controlled from each unit with a high efficiency electrostatic precipitator, manufactured by Buell Manufacturing Company, Inc. These emissions units are regulated under Acid Rain, Phase I and II; Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; and, Power Plant Siting Certification PA 77-09 conditions. FFSG Unit 1 began commercial operation in 1966. FFSG Unit 2 began commercial operation in 1969. FFSG Unit 1 is a Phase II NO_X unit and FFSG Unit 2 is a Phase I/II Early election NO_X unit. The emissions units are permitted to combust bituminous coal; a bituminous coal and bituminous coal briquette mixture; or a bituminous coal and petcoke blend. Distillate fuel oil may be burned as a startup fuel. The permittee has agreed to the use of CEMs (opacity, SO_2 and NO_X) for the purpose of periodic monitoring and currently demonstrates compliance with the sulfur dioxide standards through daily fuel analyses.

TO:
Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions units.

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1: a tangentially fired unit, rated at 440.5 MW, 3750 MMBtu/hr, burning bituminous coal; or a bituminous coal and bituminous coal briquette mixture. Distillate fuel oil may be burned as a startup fuel. Emissions are exhausted through a 499 ft. stack. This unit may also burn oily flyash.
002	Fossil Fuel Steam Generator, Unit 2: a tangentially fired unit, rated at 523.8 MW, 4795 MMBtu/hr, burning bituminous coal; or a bituminous coal and bituminous coal briquette mixture. Distillate fuel oil may be burned as a startup fuel. Emissions are exhausted through a 502 ft. stack. This unit may also burn oily flyash.

Fossil Fuel Steam Generators, Units 1 and 2, are pulverized coal dry bottom boilers, tangentially-fired. Emissions are controlled from each unit with a high efficiency electrostatic precipitator, manufactured by Buell Manufacturing Company, Inc.

A.1. Permitted Capacity. The maximum operation heat input rates are as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
001	3750	Bituminous Coal; or Bituminous Coal and Bituminous Coal Briquette Mixture
002	4795	Bituminous Coal; or Bituminous Coal and Bituminous Coal Briquette Mixture

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.]

A.3. Methods of Operation. Fuels. The only fuels allowed to be burned by this permit are: bituminous coal; a bituminous coal and bituminous coal briquette mixture, and distillate fuel oil for startup. These emissions units may also burn used oil in accordance with other conditions of this permit (see **Subsection K**). Emissions units 001 and 002 may also burn oily flyash in accordance with specific condition **A.16** of this permit.
[Rule 62-213.410, F.A.C.; 0170004-002-AO; 0170004-005-AO; and, 0170004-006-AC]

A.8. Sulfur Dioxide. The maximum sulfur dioxide emissions from the coal/briquette mixture shipment, averaged on an annual basis, shall not exceed the following:

Emissions Unit No.	Emissions Unit Description	Average Sulfur Dioxide Limit, in Pounds Per Million Btu, Heat Input
001	FFSG, Unit 1	1.67
002	FFSG, Unit 2	1.67

[Rule 62-213.440, F.A.C.; PPSC PA 77-09; and, 0170004-006-AC]

Statement of Basis:

FFSG Units 1 and 2 are pulverized coal dry bottom boilers, tangentially-fired. Emissions are controlled from each unit with a high efficiency electrostatic precipitator, manufactured by Buell Manufacturing Company, Inc. These emissions units are regulated under Acid Rain, Phase I and II; Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; and, Power Plant Siting Certification PA 77-09 conditions. FFSG Unit 1 began commercial operation in 1966. FFSG Unit 2 began commercial operation in 1969. FFSG Unit 1 is a Phase II NO_X unit and FFSG Unit 2 is a Phase I/II Early election NO_X unit. The emissions units are permitted to combust bituminous coal; or a bituminous coal and bituminous coal briquette mixture. Distillate fuel oil may be burned as a startup fuel. The permittee has agreed to the use of CEMs (opacity, SO_2 and NO_X) for the purpose of periodic monitoring and currently demonstrates compliance with the sulfur dioxide standards through daily fuel analyses.

2. Periodic Monitoring - *Conditions A.14. and B.13.*, in conjunction with *Condition I.6.*, require that the source conduct annual testing for particulate matter whenever fuel oil is burned for more than 400 hours in the preceding year. The Statement of Basis states that this testing frequency "is justified by the low emission rate documented in previous emission tests while firing fuel oil" and that the "Department has determined that sources with emissions less than half of the effective standard shall test annually."

While EPA has in the past accepted this approach as adequate periodic monitoring for particulate matter, it has done so only for uncontrolled natural gas and fuel oil-fired units. The units addressed in *Conditions A.14. and B.13.*, primarily burn coal and use add-on control equipment (i.e., electrostatic precipitators) to comply with the applicable particulate matter standards. In order to provide reasonable assurance of compliance, the results of annual stack testing will have to be supplemented with additional monitoring. Furthermore, the results of an annual test alone would not constitute an adequate basis for the annual compliance certification that the facility is required to submit for these units in order to certify continuous compliance with the pound/hour particular matter limit.

The most common approach to addressing periodic monitoring for particulate emission limits on units with add-on controls is to establish either an opacity or a control device parameter indicator range that would provide evidence of proper control device operation. The primary goal of such monitoring is to provide reasonable assurance of compliance, and one way of achieving this goal is to use opacity data or control device operating parameter data from previous successful compliance tests to identify a range of values that has corresponded to compliance in the past. Operating within the range of values identified in this manner would provide assurance that the control device is operating properly and would serve as the basis for an annual compliance certification. Depending upon the margin of compliance during the tests used to establish the opacity or control device parameter indicator range, going outside the range could represent either a period of time when an exceedence of the applicable standard is likely or it could represent a trigger for initiating corrective action to prevent an exceedence of the standard. In order to avoid any confusion regarding the consequences of going outside the indicator range, the permit should clearly state if doing so is evidence that a standard has been exceeded and should specify whether corrective action must be taken when a source operates outside the established indicator range.

PERMITTEE RESPONSE: Response - In resolution of this issue, FPC suggests that the following language replace Condition A.19 of the Title V permit. This language is based on recently approved permit language proposed by Gulf Power:

> *a. Periodic monitoring for opacity shall be COMs, which are maintained and operated in conformance with 40 CFR Part 75.*
> *b. Periodic monitoring for particulate matter shall be COMs. For any calendar quarter in which more than five percent of the COMs readings show 20% or greater opacity for Units 2, 4, and 5 and 30% or greater opacity for Unit 1 (excluding startup, shutdown, and malfunction periods), a steady-state particulate matter stack test shall be performed within the following calendar quarter. Due to the allowed opacity level of 60% for sootblowing and load changing periods for Units 1 and 2, periods of sootblowing and load changing shall also be excluded for those units. Units are not required to be brought on-line solely for the purpose of performing this special test. If the unit does not operate in the following quarter, the special test may be postponed until the unit is brought back on-line. In such cases, the special test shall be performed within 30 days.*

PROPOSED CHANGE: Specific Condition A.19. will be changed as follows:

FROM: A.19. COMS for Periodic Monitoring. The owner or operator is required to install continuous opacity monitoring systems (COMS) pursuant to 40 CFR Part 75. The owner or operator shall maintain and operate COMS and shall make and maintain records of opacity measured by the COMS, for purposes of periodic monitoring.
[Rule 62-213.440, F.A.C.]

TO: A.19. COMS for Periodic Monitoring:
a. Periodic monitoring for opacity shall be COMS, which are maintained and operated in conformance with 40 CFR Part 75.
b. Periodic monitoring for particulate matter shall be COMS. For any calendar quarter in which more than five percent of the COMS readings show 20% or greater opacity for Units 2, 4, and 5 and 30% or greater opacity for Unit 1 (excluding startup, shutdown, and malfunction periods), a steady-state particulate matter stack test shall be performed within the following calendar quarter. Due to the allowed opacity level of 60% for sootblowing and load changing periods for Units 1 and 2, periods of sootblowing and load changing shall also be excluded for those units. Units are not required to be brought on-line solely for the purpose of performing this special test. If the unit does not operate in the following quarter, the special test may be postponed until the unit is brought back on-line. In such cases, the special test shall be performed within 30 days.
[Rule 62-213.440, F.A.C.]

3. Periodic Monitoring - *Conditions C.5. and D.4.* require that the source conduct Method 9 tests once annually for the fly ash handling system (Emission Units #006, #008, #009, and #010) and the bottom ash storage silo (Emission Unit #014), respectively. For units with control equipment (i.e., baghouses), this

typically does not constitute adequate periodic monitoring to ensure continuous compliance with the visible emissions standards. It is also particularly important in this case to include adequate periodic monitoring with regard to the fly ash handling system since it has been limited to only 5 percent opacity in lieu of stack testing for particulate matter. Therefore, the permit needs to include provisions requiring that the source conduct qualitative observations of visible emissions on a daily basis (i.e., Method 22) and that Method 9 tests be conducted within 24 hours of any abnormal qualitative survey. As an alternative, since these units are controlled by baghouses, the source may opt to establish a parametric monitoring program. For instance, the permit could specify ranges for parameters, such as pressure drop, that would provide reasonable assurance that the source is in compliance with the applicable standards.

PERMITTEE RESPONSE: Response - As EPA observed in its comment letter, these emission points are tested annually for visible emissions. In every compliance test conducted on these outlets during the last five years, a six-minute average greater than 0% opacity has never occurred. The baghouse control systems on these sources are extremely reliable, reasonably assuring continuous compliance. Daily visible emissions observations are both unnecessary and impractical. Therefore, FPC requests that the permit language remain unchanged.

PROPOSED CHANGE: As requested by Florida Power Corporation, no change is proposed.

4. Periodic Monitoring - The material handling activities supporting the steam generating units (Emission Unit #016) are subject to a visible emissions limit of 20 percent opacity; however, the permit does not specify the frequency for testing. To certify compliance with the applicable opacity limit, the source should be required to conduct a Method 9 test at least once annually. To provide reasonable assurance of continuous compliance, the source needs to conduct (and record the results of) qualitative observations (i.e., Method 22) at least once daily with follow-up Method 9 tests within 24 hours of any abnormal visible emissions unless the statement of basis provides justification for reduced frequency.

PERMITTEE RESPONSE: Response - The 20% opacity limit generally applies to all of the material handling operations at the Crystal River plant, such as coal conveying and storage, fly ash storage and transport, and bottom ash storage and transport. All conveying and transport operations are covered, and there are no specific emission points. Fly ash and bottom ash storage are addressed in #3 above. Condition H.3. of the permit requires that emissions be controlled through the practices described in the Best Management Plan for the Crystal River site. This condition provides enforceable, reasonable assurance of continuous compliance. Therefore, FPC requests that the permit language remain unchanged.

PROPOSED CHANGE: As requested by Florida Power Corporation, no change is proposed.

5. Appropriate Averaging Times - *Conditions A.6., B.4.(a)(1), F.3., and G.2.* do not specify averaging times for the respective particulate matter emission limits. Because the stringency of emission limits is a function of both magnitude and averaging time, appropriate averaging times must be added to the permit in order for the limits to be practicably enforceable. An approach that may be used to address this deficiency is to include a general condition in the permit stating that the averaging times for all specified emission standards are tied to or based on the run time of the test method(s) used for determining compliance.

PERMITTEE RESPONSE: Response - FPC disagrees with EPA's objection. As stated in previous FPC responses, the subject conditions in the Proposed Title V permit already contain all that is necessary to make them completely (and therefore practicably) enforceable: a requirement, and a method for determining compliance with that requirement.

However, in an effort to move the Title V permitting process to conclusion, FPC is willing to accept the inclusion of a "permitting note" following Conditions A.7 and A.8, as follows:

> *The averaging time for the particulate matter standard corresponds to the cumulative sampling time of the specified test method.*

FPC's suggested resolution of this matter does not constitute or imply concurrence with EPA's position. The Title V process is intended to consolidate existing applicable requirements for each Title V permit on a case-by-case basis, and FPC's suggested resolution applies only to the Crystal River Title V facility/permit. Moreover, the language suggested above is applicable only to the existing particulate matter limit and only for the existing compliance determination method for this limit.

PROPOSED CHANGE: A permitting note will be added following Specific Conditions A.7. and A.8. as follows:

> **ADD:** {Permitting note: The averaging time for the particulate matter standard corresponds to the cumulative sampling time of the specified test method.}

6. <u>Periodic Monitoring (Practical Enforceability)</u> - *Conditions C.1. and D.1.* limit the mass flow rates of fly ash through the fly ash handling system and bottom ash through the bottom ash storage silo, respectively; however, the permit does not contain any provisions to practicably enforce such limits. The permit needs to include monitoring and/or recordkeeping requirements such as the maintenance of daily records of the mass throughputs for the affected units to provide reasonable assurance of compliance with the applicable limits.

PERMITTEE RESPONSE: Response - The mass flow rate limits given in the permit are actually the design limits of the equipment, and therefore they cannot physically be exceeded. Therefore, no additional monitoring is necessary. In addition, there is no monitoring method by which to measure the mass flow rates of the fly ash and bottom ash through the handling systems.

PROPOSED CHANGE: As requested by Florida Power Corporation, no change is proposed.

7. <u>Periodic Monitoring (Practical Enforceability)</u> - *Conditions F.1. and G.1.* limit the volume flow rates of seawater through the cooling towers, Emission Units #013 and #015, respectively; however, the permit does not contain any provisions to practicably enforce such limits. The permit needs to include provisions requiring the source to monitor and record the flow of seawater through the cooling towers.

PERMITTEE RESPONSE: Response - The original construction and operation permits for these cooling towers contained design maximum flow rates for informational purposes only. These design rates were used to develop the particulate emission limits for the towers. To address this issue, the permit language should be corrected by removing the seawater flow rates as permit limitations. The only permit limits appropriate to these units are those for particulate emissions and operating hours, as reflected in prior permits.

PROPOSED CHANGE: The Department feels that the seawater flow rates are an easily measurable way to determine the percent operating capacity of these units. As such, the following permitting note will be added to Specific Conditions F.1. and G.1. as follows:

ADD: {Permitting note: The seawater flow rate limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load) and to aid in determining future rule applicability. Regular record keeping is not required for seawater flow rates. Instead the owner or operator is expected to determine the seawater flow rate whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such seawater flow rate determination may be based on measurements of flow by various methods including but not limited to flow metering or the use of pump curves supplied by the manufacturer to calculate an average hourly seawater flow rate during the test.}

II. EPA General Comments

1. Compliance Certification - Facility-wide *Condition 11* of the permit should specifically reference the required components of Appendix TV-3, which lists the compliance certification requirements of 40 C.F.R. §70.6(c)(5)(iii), to ensure that complete certification information is submitted to EPA.

PERMITTEE RESPONSE: None.

PROPOSED CHANGE: Facility-wide Specific Condition 11. will be changed as follows:

FROM: 11. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year.
[Rule 62-214.420(11), F.A.C.]

TO: 11. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition 51., APPENDIX TV-3, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

2. Acid Rain - The Phase II Acid Rain Application and Compliance Plan received on December 22, 1995, which are referenced as attachments made part of the permit (see page 1 of proposed permit), should also be referenced under Section IV, Subsection A.1.

PERMITTEE RESPONSE: None.

PROPOSED CHANGE: Specific Condition A.1. of the Acid Rain Part will be changed as follows:

FROM: A.1. The Phase II permit application(s) submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:
a. DEP Form No. 62-210.900(1)(a), dated July 1, 1995.
[Chapter 62-213, F.A.C., and Rule 62-214.320, F.A.C.]

TO: A.1. The Phase II permit application(s) submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:
a. DEP Form No. 62-210.900(1)(a), dated July 1, 1995.
b. Phase II Acid Rain Application/Compliance Plan received 12/22/95
[Chapter 62-213, F.A.C., and Rule 62-214.320, F.A.C.]

3. Acid Rain - The NOx Early Election requirements and limits located in Subsection B (addressing Phase I Acid Rain) for Units 2, 4, and 5 of the Acid Rain part of the proposed title V permit should be moved to Subsection A (addressing Acid Rain, Phase II). Moving these requirements should clarify that FDEP is approving and incorporating the NOx Early Election requirements into the Phase II permit portion.

PERMITTEE RESPONSE: None.

PROPOSED CHANGE: Florida is required by statute to issue the Acid Rain part of the permit concurrently with the Title V permit. Since the facility elected into the Phase I Early Election Plans for NO_X, of the NO_X requirements are contained in Subsection B of the Acid Rain Part of the permit. In order to eliminate any confusion, Specific Condition A.2. will be changed as follows:

FROM: A.2. Sulfur dioxide (SO_2) allowance allocations and nitrogen oxide (NO_x) requirements for each Acid Rain unit is as follows:

TO: A.2. Sulfur dioxide (SO_2) allowance allocations for each Acid Rain unit is as follows:

As you know, the 90 day period ends January 30th. All parties involved have been expeditiously seeking resolution of these issues. We feel that EPA's concerns have been adequately addressed and we look forward to issuing final permits. Please advise as soon as possible if you concur with the specific changes detailed above. Please call me at 850/921-9503 if you have any questions. You may also contact Mr. Scott M. Sheplak, P.E., at 850/921-9532, or Mr. Edward J. Svec at 850/921-8985, if you need any additional information.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CF/es

Attachments

cc: Scott M. Sheplak
Pat Comer
J. M. Kennedy, FPC