Golder Associates

April 27, 2010 093-87718

Mr. Jeffery F. Koerner, P.E.
New Source Review Section Administrator
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: REQUEST FOR ADDITIONAL INFORMATION DATED MARCH 3, 2010
PROJECT NO. 0310045-029-AC
ST. JOHNS RIVER POWER PARK UNITS 1 AND 2
REQUEST TO AUTHORIZE CONTINUOUS FIRING OF NATURAL GAS DURING NORMAL OPERATIONS

Dear Mr. Koerner:

JEA has received a request for additional information (RAI) from the Florida Department of Environmental Protection (FDEP) dated March 3, 2010, regarding the air construction permit application (FDEP Project No. 0310045-029-AC) submitted on February 9, 2010, to authorize continuous firing of natural gas in St. Johns River Power Park (SJRPP) Units 1 and 2 during normal operations.

The RAI specifically asks for a regulatory applicability determination regarding the New Source Performance Standards (NSPS) Subpart Da for the firing of natural gas in Units 1 and 2. Subpart Da currently applies to Units 1 and 2, and the current Title V Operating Permit No. 0310045-016-AV lists the emissions standards, monitoring, reporting, and record keeping requirements pursuant to the Subpart. It is Golder's understanding that the particulate matter (PM) and sulfur dioxide (SO_2) standards of Subpart Da, as described in Title 40, Part 60.42Da of the Code of Federal Regulations (40 CFR 60.42Da), and 40 CFR 60.43Da, respectively, apply to gaseous fuel, which, as defined in 40 CFR 60.41Da, is different from natural gas. 40 CFR 60 Section 60.41Da defines gaseous fuel as "any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal" and provides a separate definition for natural gas. The numerical emissions standards for PM and SO_2 in Subpart Da are described to be applicable during the combustion of solid, liquid, or gaseous fuels; however, natural gas has no regulatory precedent for limiting emission of PM or SO_2 under Subpart Da, as emissions of these air pollutants due to burning natural gas are negligible.

The emissions standards for nitrogen oxides (NO_x) as specified in 40 CFR 60.44Da(a)(1) and (2), are also described to be applicable to gaseous fuel and not to natural gas. However, NO_x has a historical basis as being applicable to natural gas prior to the definition of "gaseous fuel," which was first introduced in 2006. Pending clear guidance from the U.S. Environmental Protection Agency (EPA) on the reasons for separating natural gas from gaseous fuel, JEA proposes to accept the PM, SO_2, and NO_x emissions standards for gaseous fuel as the emissions standards for natural gas.

It is proposed that Specific Conditions D.15 and D.16 of the current Title V Operating Permit No. 0310045-016-AV be revised as follows to include natural gas as a gaseous fuel (pursuant to February 28, 2005 Federal Register):

D.6. <u>Particulate Matter</u>. No owner or operator shall cause to be discharged into the atmosphere from any emissions unit any gases which contain particulate matter in excess of:
(1) 0.03 lb/million Btu heat input derived from the combustion of solid, liquid, or gaseous fuel (coal, a blend of coal and petroleum coke, fuel oil, or gaseous fuel);

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel (coal or a blend of coal and petroleum coke), and
(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.
(4) Particulate matter emissions shall be controlled with an electrostatic precipitator.
[40 CFR 60.42a(a)(1), (2) & (3); PSD-FL-010 and BACT; PA 81-13; and, PSD-FL-010(A & B)]

D.14. Sulfur Dioxide: When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:
(1) If emissions of SO_2 to the atmosphere are greater than 260 ng/J (0.60 lb/MMBtu) heat input:
$PS_{SO2} = (340X + 520Y) / 100$ and
$\%P_S = 10$

(2) If emissions of SO_2 to the atmosphere are equal to or less than 260 ng/J (0.60 lb/MMBtu) heat input:
$PS_{SO2} = (340X + 520Y) / 100$ and
$\%P_S = (10X + 30Y)/100$

where:
PS_{SO2} = Prorated SO_2 emission limit (ng/J heat input);
$\%P_S$ = Percentage of potential SO_2 emission allowed;
X = Percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels).
Y = Percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels)
[40 CFR 60.43a(h)(1) & (2)]

D.15. Nitrogen Oxides: No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides in excess of the following emission limits, based on a 30-day rolling average.
(1) NO_x emissions limits.
a. Coal or coal-petroleum coke blend: 0.60 lb/million Btu (260 ng/J) heat input;
b. Fuel oil: 130 ng/J (0.30 lb/million Btu) heat input~~.~~;
c. Natural gas: 86 ng/J (0.20 lb/million Btu) heat input.
(2) NO_x reduction requirement.
a. Solid fuels: 65 percent reduction of potential combustion concentration;
b. Liquid fuels: 30 percent reduction of potential combustion concentration~~.~~;
c. Gaseous fuel: 25 percent reduction of potential combustion concentration.
[40 CFR 60.44a(a)(1) and (2)]

D.16. Nitrogen Oxides: When two or more fuels [fuel oil, coal (or a blend of coal and petroleum coke), natural gas] are combusted simultaneously, the applicable standard is determined by proration using the following formula:
$PS_{NOX} = (130X + 260Y + 86Z) / 100$

where:
PS_{NOX} = the prorated standard for nitrogen oxides when multiple fuels [coal (or a blend of coal and petroleum coke), fuel oil, and natural gas] are combusted simultaneously (ng/J heat input)
X = the percentage of total heat input derived from the combustion of fuel oil
Y = the percentage of total heat input derived from the combustion of coal or a blend of coal and petroleum coke
Z = the percentage of total heat input derived from the combustion of natural gas
[40 CFR 60.44a(c) and PSD-FL-010]

Revised Tables 2 and 5 are provided in Attachment A, which shows future potential NO_x emissions due to natural gas combustion based on the Subpart Da NO_x limit of 0.20 pound per million British thermal units (lb/MMBtu). As a result, the revised potential decrease in NO_x emissions is shown as 1,351.6 tons per year (TPY). As described in the application, natural gas when used during normal operation is co-fired with coal and the resulting NO_x emissions are controlled using a selective catalytic reduction (SCR) system that will achieve a combined NO_x emission rate less than the Subpart Da NO_x emission limit.

Thank you for consideration of this information. If you have any questions, please do not hesitate to call us at (352) 336-5600 or via email (kkosky@golder.com and smohammad@golder.com).

Sincerely,

GOLDER ASSOCIATES INC.

Kennard F. Kosky

Kennard Kosky, P.E.
Principal Engineer

Salahuddin Mohammad
Senior Project Engineer

cc: B. Gianazza, JEA

Enclosures

SKM/tz

TABLE 1
SJRPP UNITS 1 & 2 ANNUAL HEAT INPUTS, 2003-2008

	Heat Input from Distillate Oil (MMBtu/yr)			Heat Input from Bituminous Coal (MMBtu/yr)			Heat Input from Coke (MMBtu/yr)			Total Actual Heat Input (MMBtu/yr)			Actual Operating Hours (hr/yr)	
Year	Unit 1	Unit 2	Total	Unit 1	Unit 2	Total	Unit 1	Unit 2	Total	Unit 1	Unit 2	Total	Unit 1	Unit 2
2008	140,836	68,637	209,473	44,790,592	44,519,444	89,310,036	0	0	0	44,931,428	44,588,081	89,519,509	8,117	7,485
2007	122,889	119,053	241,942	46,296,263	39,871,811	86,168,074	145,684	7,379,596	7,525,280	46,564,836	47,370,460	93,935,296	8,299	8,574
2006	172,483	172,072	344,555	40,511,088	31,657,200	72,168,288	8,905,736	12,226,900	21,132,636	49,589,307	44,056,172	93,645,479	8,524	7,611
2005	321,539	206,596	528,135	30,563,320	36,479,775	67,043,095	9,170,177	10,902,956	20,073,133	40,055,036	47,589,327	87,644,363	7,180	8,728
2004	503,886	362,639	866,525	41,862,456	32,498,592	74,361,048	9,193,116	6,520,041	15,713,157	51,559,458	39,381,272	90,940,730	8,774	7,066
2003	347,158	106,860	454,018	37,259,825	41,966,400	79,226,225	8,199,549	7,695,648	15,895,197	45,806,532	49,768,908	95,575,440	7,882	7,882

Note: All values are based on annual operating reports for the period 2003 - 2008.

TABLE 2 (Rev. 2)
FUTURE POTENTIAL EMISSIONS FOR UNITS 1 & 2 DUE TO NATURAL GAS FIRING

Pollutant	Potential Hourly Heat Input [a] (MMBtu/hr)	Potential Annual Heat Input [b] (MMBtu/yr)	Natural Gas Heat Content [c] (MMBtu/10^6 scf)	Natural Gas Consumption Hourly (10^6 scf/hr)	Natural Gas Consumption Annual (10^6 scf/yr)	Emission Factor [d]		Hourly Emissions (lb/hr)	Annual Emissions (TPY)
NO_x	1,400.0	12,264,000	1,022	1.37	12,000.0	0.20	lb/MMBtu	280.0	1,226.4
CO	1,400.0	12,264,000	1,022	1.37	12,000.0	84	lb/10^6 scf	115.1	504.0
SO_2	1,400.0	12,264,000	1,022	1.37	12,000.0	0.6	lb/10^6 scf	0.8	3.6
VOC	1,400.0	12,264,000	1,022	1.37	12,000.0	5.5	lb/10^6 scf	7.5	33.0
PM	1,400.0	12,264,000	1,022	1.37	12,000.0	1.9	lb/10^6 scf	2.6	11.4
PM_{10}	1,400.0	12,264,000	1,022	1.37	12,000.0	1.9	lb/10^6 scf	2.6	11.4
SAM	1,400.0	12,264,000	1,022	1.37	12,000.0	0.046	lb/10^6 scf	0.06	0.28

[a] Hourly heat input based on 28 igniters for each unit, each igniter rated at 25 MMBtu/hr.
[b] Potential annual heat input based on 8,760 hr/yr operation.
[c] Based on natural gas heat content of 1,022 Btu/scf.
[d] Tables 1.4-1 and 1.4-2, Section 1.4, AP-42. SAM emission factor based on AP-42 Section 1.3 for fuel oil burning - 5% (1 to 5%) of the SO_2 is further oxidized to SO_3, which then converts to SAM (98/80).

Golder Associates

March 26, 2010 093-87718

Mr. Jeffery F. Koerner, P.E.
New Source Review Section Administrator
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

**RE: REQUEST FOR ADDITIONAL INFORMATION DATED MARCH 3, 2010
PROJECT NO. 0310045-029-AC
ST. JOHNS RIVER POWER PARK UNITS 1 AND 2
REQUEST TO AUTHORIZE CONTINUOUS FIRING OF NATURAL GAS DURING NORMAL OPERATIONS**

Dear Mr. Koerner:

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The RAI specifically asks for a regulatory applicability determination regarding the New Source Performance Standards (NSPS) Subpart Da for the firing of natural gas in Units 1 and 2. Subpart Da currently applies to Units 1 and 2, and the current Title V Operating Permit No. 0310045-016-AV lists the emissions standards, monitoring, reporting, and record keeping requirements pursuant to the Subpart. It is Golder's understanding that the particulate matter (PM) and sulfur dioxide (SO_2) standards of Subpart Da, as described in Title 40, Part 60.42Da of the Code of Federal Regulations (40 CFR 60.42Da), and 40 CFR 60.43Da, respectively, apply to gaseous fuel, which, as defined in 40 CFR 60.41Da, is different from natural gas. 40 CFR 60 Section 60.41Da defines gaseous fuel as "any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal" and provides a separate definition for natural gas. The numerical emissions standards for PM and SO_2 in Subpart Da are described to be applicable during the combustion of solid, liquid, or gaseous fuels; however, natural gas has no regulatory precedent for limiting emission of PM or SO_2 under Subpart Da, as emissions of these air pollutants due to burning natural gas are negligible.

The emissions standards for nitrogen oxides (NO_x) as specified in 40 CFR 60.44Da(a)(1) and (2), are also described to be applicable to gaseous fuel and not to natural gas. However, NO_x has a historical basis as being applicable to natural gas prior to the definition of "gaseous fuel," which was first introduced in 2006. Pending clear guidance from the U.S. Environmental Protection Agency (EPA) on the reasons for separating natural gas from gaseous fuel, JEA proposes to accept the NO_x emissions standards for gaseous fuel as the emissions standards for natural gas.

It is proposed that Specific Conditions D.15 and D.16 of the current Title V Operating Permit No. 0310045-016-AV be revised as follows to include natural gas:

D.15. <u>Nitrogen Oxides</u>: No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides in excess of the following emission limits, based on a 30-day rolling average.
(1) NO_x emissions limits.
   a. Coal or coal-petroleum coke blend: 0.60 lb/million Btu (260 ng/J) heat input;
   b. Fuel oil: 130 ng/J (0.30 lb/million Btu) heat input~~.~~;

c. Natural gas: 86 ng/J (0.20 lb/million Btu) heat input.
(2) NO_x reduction requirement.
a. Solid fuels: 65 percent reduction of potential combustion concentration;
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$PS_{NOX} = (130X + 260Y + 86Z) / 100$

where:

PS_{NOX} = the prorated standard for nitrogen oxides when multiple fuels [coal (or a blend of coal and petroleum coke), fuel oil, and natural gas] are combusted simultaneously (ng/J heat input)
X = the percentage of total heat input derived from the combustion of fuel oil
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Z = the percentage of total heat input derived from the combustion of natural gas
[40 CFR 60.44a(c) and PSD-FL-010]

Revised Tables 2 and 5 are provided in Attachment A, which shows future potential NO_x emissions due to natural gas combustion based on the Subpart Da NO_x limit of 0.20 pound per million British thermal units (lb/MMBtu). As a result, the revised potential decrease in NO_x emissions is shown as 1,351.6 tons per year (TPY). As described in the application, natural gas when used during normal operation is co-fired with coal and the resulting NO_x emissions are controlled using a selective catalytic reduction (SCR) system that will achieve a combined NO_x emission rate less than the Subpart Da NO_x emission limit.

Thank you for consideration of this information. If you have any questions, please do not hesitate to call us at (352) 336-5600 or via email (kkosky@golder.com and smohammad@golder.com).

Sincerely,

GOLDER ASSOCIATES INC.

Kennard Kosky, P.E.
Principal Engineer

Salahuddin Mohammad
Senior Project Engineer

cc: B. Gianazza, JEA

Enclosures

SKM/tz

TABLE 2 (Rev. 2)
FUTURE POTENTIAL EMISSIONS FOR UNITS 1 & 2 DUE TO NATURAL GAS FIRING

Pollutant	Potential Hourly Heat Input [a] (MMBtu/hr)	Potential Annual Heat Input [b] (MMBtu/yr)	Natural Gas Heat Content [c] ($MMBtu/10^6$ scf)	Natural Gas Consumption Hourly (10^6 scf/hr)	Natural Gas Consumption Annual (10^6 scf/yr)	Emission Factor [d]		Hourly Emissions (lb/hr)	Annual Emissions (TPY)
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CO	1,400.0	12,264,000	1,022	1.37	12,000.0	84	$lb/10^6$ scf	115.1	504.0
SO_2	1,400.0	12,264,000	1,022	1.37	12,000.0	0.6	$lb/10^6$ scf	0.8	3.6
VOC	1,400.0	12,264,000	1,022	1.37	12,000.0	5.5	$lb/10^6$ scf	7.5	33.0
PM	1,400.0	12,264,000	1,022	1.37	12,000.0	1.9	$lb/10^6$ scf	2.6	11.4
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SAM	1,400.0	12,264,000	1,022	1.37	12,000.0	0.046	$lb/10^6$ scf	0.06	0.28

[a] Hourly heat input based on 28 igniters for each unit, each igniter rated at 25 MMBtu/hr.
[b] Potential annual heat input based on 8,760 hr/yr operation.
[c] Based on natural gas heat content of 1,022 Btu/scf.
[d] Tables 1.4-1 and 1.4-2, Section 1.4, AP-42. SAM emission factor based on AP-42 Section 1.3 for fuel oil burning - 5% (1 to 5%) of the SO_2 is further oxidized to SO_3, which then converts to SAM (98/80).

TABLE 5 (Rev. 2)
PSD APPLICABILITY - SJRPP UNITS 1 & 2
NATURAL GAS FIRING

Pollutant	Latest 2-Year (2007-2008) Average Emissions[a] (TPY)	Latest 2-Year (2007-2008) Average Heat Input[a] (MMBtu/yr)	Current Actual Emission Rates (lb/MMBtu)	Current Actual Emissions for Heat Input Potential of Natural Gas[c] (TPY)	Future Potential Emissions [d] (TPY)	Increase/Decrease in Emissions (Future – Current Actual) (TPY)	PSD Significant Emission Rates (TPY)
NO_x	19,282	91,727,403	0.42	2,578.0	1226.4	-1351.6	40
CO	7,978	91,727,403	0.17	1,066.6	504.0	-562.6	100
SO_2	10,943	91,727,403	0.24	1,463.1	3.6	-1459.5	40
VOC	121	91,727,403	0.0026	16.1	33.0	16.9	40
PM [e]	144	91,727,403	0.0035	21.5	11.4	-10.1	25
PM_{10} [f]	76	91,727,403	0.0029	18.0	11.4	-6.6	15
SAM[g]	NA	NA	NA	NA	0.3	0.3	7

[a] Based on AOR data for 2003 - 2008, see Table 4.

[b] Based on AOR data for 2003 - 2008, see Table 1.

[c] See Table 2 for heat input potential for natural gas, which is the potential amount of current actual heat input to be replaced by natural gas.

[d] Future potential emissions based on heat input potential of natural gas, see Table 2.

[e] Current actual PM emission rate in lb/MMBtu is based on stack test data from 2003-2008 from FDEP ARMS database.

[f] Current PM_{10} emission rate in lb/MMBtu is based on the ratio of PM to PM_{10} emission in Table 1.1-6 for dry bottom boilers with an ESP. Ratio is 0.054/0.064 = 84%.

[g] SAM emissions data are not available (NA) in the AORs for 2003 - 2008.

Golder Associates

June 24, 2010 093-87718

Mr. Robert Bull, P.E.
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: PROJECT NO. 0310045-029-AC
ST. JOHNS RIVER POWER PARK UNITS 1 & 2
COMMENTS ON DRAFT PERMIT

Dear Mr. Bull:

On behalf of Jacksonville Electric Authority (JEA)/St. Johns River Power Park (SJRPP) we offer the following comments for consideration. As you will note, the comments are very minor and will not materially affect the Florida Department of Environmental Protection's (FDEP's) analysis and conditions.

Draft Permit, Pages 5 of 6 and 6 of 6, Section 3, Emissions Unit Specific Conditions (Draft), Condition 3, Nitrogen Oxides (NO_x). There were minor references to the Code of Federal Regulation (CFR) that should be updated in the final permit to reflect the precise citations in the CFR. These are as follows:

Condition 3: (1) "0.20 lb/MMBtu [40 CFR 60.44Da(a)(1)]", {Changed from 40 CFR 60.44a(b)(1) in draft permit.}

Condition 3: (2) "25 percent reduction [40 CFR 60.44Da(a)(2)]." {Changed from 40 CFR 60.44a(b)(2) in draft permit.} "Compliance with the NO_x emission limitation under 40 CFR 60.44Da(a)(1) constitutes compliance with the percent reduction requirements under 60.44Da(a)(2). [40 CFR 60.48Da(b)]" {Change from 40 CFR 60.48d(b)}

Condition 4: Change the reference to [40 CFR 60.44Da(c)] {Changed from 40 CFR 60.44a(c)}

Condition 5: Change the reference to [40 CFR 60.48Da(g)(1)] {Changed from 40 CFR 60.48a(g)}

Technical Evaluation and Preliminary Determination (TE&PD). There are minor values that were noted to be different from the information submitted. However, these did not change FDEP's analysis.

On Page 3 of 5 in the Project Description, Last Paragraph the natural gas quantity of 12,533 MMscf/year should be 12,000 MMscf/year based on the natural gas heat content of 1022 Btu/scf (see Segment 3 of 4 in the application. The calculation is based on the annual heat input of 12,264,000 MMBtu/year (700 MMBtu/hr/unit x 2 units x 8,760 hours/year). The difference, however, does not change FDEP's analysis in the TE&PD.

On Page 5 of 5 in the emission factor table showing baseline actual emissions and projected actual emissions the projected actual emission factor in lb/MMBtu shown as 0.02 for NO_x should have been 0.20 based on the subsequent information submitted in April 2010. However, this is still much less than the baseline actual of 0.42 lb/MMBtu and does not change FDEP's conclusions.

Golder Associates Inc.
6026 NW 1st Place
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Tel: (352) 336-5600 Fax: (352) 336-6603 www.golder.com

If you have any questions, please do not hesitate to call us at (352) 336-5600 or via email (kkosky@golder.com and smohammad@golder.com).

Sincerely,

GOLDER ASSOCIATES INC.

Kennard Kosky, P.E.
Principal Engineer

Salahuddin K. Mohammad
Senior Project Engineer

cc: cc: B. Gianazza, JEA
J. Worley, JEA

KFK/SKM/tlc