

January 26, 2001

Mr. Alvaro Linero Administrator, New Source Review Section Bureau of Air Regulation Department of Environmental Protection 111 South Magnolia Drive, Suite 4 Tallahassee, FL 32301

Re: CPV Gulfcoast, Ltd. Response to EPA Region IV comments dated

December 27, 2000

File No. 0810194-001-AC (PSD-FL-300), CPV Gulfcoast Power GeneratingFacility

Dear Mr. Linero:

Following are CPV Gulfcoast, Ltd.'s response to EPA Region IV comments filed in a letter to DEP dated December 27, 2000.

CPV has revised the BACT calculations to incorporate the concerns raised by EPA Region IV. The revisions include four cases based on the EPA comments. The cases are attached.

Case 1: All comments of EPA Region IV are incorporated into the calculations of oxidation catalyst cost effectiveness. The revised calculations result in an oxidation catalyst cost estimate of \$3,050 per ton of CO removed.

Case 2: All comments of EPA region IV are incorporated into the calculations of oxidation catalyst cost effectiveness with the exception of the change in interest rate. The interest rate is maintained at 8% in this case. CPV believes this interest rate is an appropriate representation of the rates available to merchant generating facilities. The

Additionally, since the PSD permit contains a separate CO emission limit (15 ppmvd) when the CT is operating in power augmentation mode, the PSD permit should also include a definition of power augmentation mode.

- 2. As previously discussed with FDEP staff, in lieu of PM/PM₁₀ emission limits in the PSD permit, compliance with the CO emission limits will serve as an indicator that good combustion practices are being maintained. Since Condition 16 (PM/PM₁₀ and Visible Emissions) does not include PM/PM₁₀ emission limits, Condition 16 should be modified to include language that clarifies the relationship between CO and PM/PM₁₀ emissions.
- 3. Our comments concerning the CO catalytic oxidation and SCONOxTM cost analyses are as follows:
 - a. The SCONOxTM cost analysis was performed using a controlled NO_x emission level of 3.5 ppmvd. The SCONOxTM cost analysis should be redone using the lower emission level achievable by the SCONOxTM pollution control system (about 2 ppmvd).
 - b. The capital recovery costs in Table E-2 (SCONOxTM) and Table E-3 (catalytic oxidation) are too high because they contain a double-counting of catalyst costs. Catalyst cost is already included in the annualized "Replacement Catalyst" cost and should be deducted from the "Total Capital Investment" when calculating capital recovery. This concept is explained in the following excerpt from the U.S. Environmental Protection Agency's OAQPS Control Cost Manual: "However, whenever there are parts in the control system that must be replaced before the end of its useful life, Equation 2.2 [the capital recovery cost calculation equation] must be adjusted, to avoid double-counting."
 - c. The "Total Capital Investments" sections of Table E-2 and Table E-3 include a 20 percent contingency fee. This is inconsistent with the OAQPS Control Cost Manual, which includes a 3 percent contingency fee. CPV-Atlantic's 20 percent contingency fee is much higher than what is normally used in SCONOxTM or CO catalytic oxidation cost analyses and should be reduced unless the need for such a high contingency fee can be well documented.
 - d In addition to the "Fuel Penalty" costs, Table E-3 also includes a cost figure which accounts for the lost revenue from a "Pressure Drop Derate." Although it is appropriate to calculate the cost of using additional natural gas to compensate for the power consumption resulting from pressure drops across the catalyst bed, lost revenue should not be included in the cost analysis and should be omitted.
 - e. An interest rate of 8 percent may be appropriate for the CPV-Atlantic facility; however, it should be noted that the current version of the *OAQPS Control Cost Manual* uses an interest rate of 7 percent. If there is justification for CPV-Atlantic to use a higher interest rate, documentation should be provided.

revised calculations result in an oxidation cost estimate of \$3,088 per ton of CO removed.

Case 3: All comments of EPA Region IV are incorporated into the calculations of oxidation catalyst cost effectiveness with the exception of the reduction in contingency costs. The contingency cost is maintained at 20% in this case. CPV believes this level of contingency is appropriate given the level of activity and uncertainty in the generating industry at this time. The revised calculations result in an oxidation cost estimate of \$3,290 per ton of CO removed.

Case 4: All comments of EPA Region IV are incorporated into the calculations of oxidation catalyst cost effectiveness with the exception of the change in derate. CPV has maintained the original derate as it represents a true cost to the facility. The revised calculations result in an oxidation catalyst cost estimate of \$3,870 per ton of CO removed.

CPV does not believe an oxidation catalyst is cost effective for this project in any of the four cases presented.

If DEP has any questions regarding these revisions, please do not hesitate to contact me at 781-848-0253. We appreciate the opportunity to work with you to resolve these issues and we look forward to expeditious issuance of the permit.

Sincerely,

Sean Finnerty Director, Project Development

Attachements.

CC: Gary Lambert Cathy Sellers

NDIRECT INSTALLATION COSTS	Table E-3. CPV Gulf Coast	
DIRECT COSTS		in this cast in last
Purchased Equipment Costs 556,000		SE PROCUSTORE NO
Sales Tax (8% of purchased equipment costs) \$33,800 Freight (4% of purchased equipment costs) \$22,400 \$3616,000 \$3		
Subtotal-Purchased Equipment Costs (PEC) \$16,000		
Direct Installation Costs S196,000		
Direct Installation Costs S196,000	- ' ' ' '	\$616,000
Subtotal-Direct Installation Costs \$196,000		,
TOTAL DIRECT COSTS (TDC) \$812,000	Installation/Foundation (35% of Catalyst Capital Cost)	\$196,000
NDIRECT INSTALLATION COSTS Engineering Costs (6% of PEC) Contengency (35% per pg 3-50 of EPA 453/8-96-001, reduced from 20% item 2e of EPA letter dated 12-27-00) \$24,360	Subtotal-Direct Installation Costs	\$196,000
Engineering Costs (5% of PEC) Cortingency (3% per pg 3-50 of EPA 453/8-96-001, reduced from 20% item 2e of EPA letter dated 12-27-00) \$24,360 TOTAL INDIRECT COSTS \$55,160 TOTAL CAPITAL INVESTIMENT (TCI) DIRECT ANNUAL COSTS \$100% Capacity factor	TOTAL DIRECT COSTS (TDC)	\$812,000
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TOTAL INDRECT COSTS \$55,160	Contingency (3% per pg 3-50 of EPA 453/B-96-001, reduced from 20% item 2e	
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16,265 mmBtuyr natural gas 2,25 mmBtu natural gas 2,25 mmBtu natural gas 316,667 \$	1.807E+09 Annual CTG output, kW-hr	\$30,580
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Uncontrolled General Electric 7FA Turbine Emissions = 9 ppm on gas for 6,040 hr/yr (no power augmentation)/ 15 ppm on gas for 2,000 hr/yr (power augmentation)/20 ppm on oil for 720 hr/yr (DNS OF CO REMOVED PER YEAR 123 Controlled General Electric 7FA Turbine Emissions = assume 80% control efficiency COST-EFFECTIVENESS ENVIRONMENTAL BASIS	BASELINE POTENTIAL CO EMISSIONS (TPY) FROM TURBINE	154
TONS OF CO REMOVED PER YEAR Controlled General Electric 7FA Turbine Emissions = assume 80% control efficiency COST-EFFECTIVENESS ENVIRONMENTAL BASIS	Uncontrolled General Electric 7FA Turbine Emissions = 9 ppm on gas for 6,040 hr/yr (no power	-3-
Controlled General Electric 7FA Turbine Emissions = assume 80% control efficiency COST-EFFECTIVENESS ENVIRONMENTAL BASIS		123
ENVIRONMENTAL BASIS	Controlled General Electric 7FA Turbine Emissions = assume 80% control efficiency	140
ENVIRONMENTAL BASIS	COST.EFFECTIVENESS	
(\$ per ton of CO removed) \$3,870	ENVIRONMENTAL BASIS	
l ·	(\$ per ton of CO removed)	\$3,870

Holladay, Cleve

From: Sent:

Dee Morse [Dee_Morse@nps.gov] Tuesday, January 23, 2001 1:51 PM Holladay, Cleve Re: PSD Class I Analysis for CPV Atlantic

To:

Subject:

cc:Mail note part

cc:Mail note part

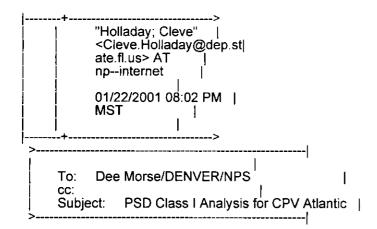
Cleve,

Thanks for the information on this CPV Atlantic Power Generating Facility. Given the emissions (126 TPY of NOx, 76 TPY of SO2, and 103 TPY of PM10) and the distance (180 km) from Everglades to the source location we do not have any concerns that this source will have potential significant impacts on AQRVs at Everglades NP.

Thanks for keeping us informed.

Dee Morse Air Resources Division National Park Service Phone: 303 969-2817 Fax: 303 969-2822

e-mail: dee_morse@nps.gov





Department of Environmental Protection

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

David B. Struhs Secretary

January 11, 2001

Mr. Gregg Worley, Chief Air, Radiation Technology Branch Preconstruction/HAP Section U.S. EPA, Region 4 61 Forsyth Street Atlanta, Georgia 30303

RE: CPV Atlantic, Ltd.
CPV Atlantic Power Generating Facility
Facility ID No. 1110101-001-AC, PSD-FL-312

Dear Mr. Worley:

Enclosed for your review and comment is an application for CPV Atlantic, Ltd. to construct a 250 MW combined-cycle power generation facility in St. Lucie County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact me at 850/921-9523.

Sincerely,

Al Linero, P.E.

Administrator

New Source Review Section

Path adams

AAL/pa

Enclosure

"More Protection, Less Process"

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Department of Environmental Protection

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

David B. Struhs Secretary

January 11, 2001

Mr. John Bunyak, Chief Policy, Planning & Permit Review Branch NPS – Air Quality Division Post Office Box 25287 Denver, Colorado 80225

RE: CPV Atlantic, Ltd.

CPV Atlantic Power Generating Facility Facility ID No. 1110101-001-AC, PSD-FL-312

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for CPV Atlantic, Ltd. to construct a 250 MW combined-cycle power generation facility in St. Lucie County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact me at 850/921-9523.

Sincerely,

Al Linero, P.E. Administrator

New Source Review Section

AAL/pa

Enclosure