Georgia-Pacific

Palatka Pulp and Paper Operations
Consumer Products Division

P.O. Box 919
Palatka, FL 32178-0919
(386) 325-2001

September 7, 2004

RECEIVED

SEP 13 2004

BUREAU OF AIR REGULATION

Ms. Trina L. Vielhauer
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Request for Additional Information (RAI)
Bark Hog Replacement – No. 4 Combination Boiler
Project No. 1070005-028-AC/PSD-FL-341

Dear Ms. Vielhauer,

We are in receipt of your Request for Additional Information (RAI), dated August 12, 2004. The Department's question, re-stated in italics, is followed by our response.

1. *Due to a significant increase in carbon monoxide (CO) emissions from the Combination Boiler, a BACT (Best Available Control Technology) determination is required pursuant to Rule 62-212.400(5), F.A.C. Please provide a BACT determination pursuant to Rule 62-212.400(6), F.A.C.*

Response:

In Georgia-Pacific's view, neither Rule 62-212.400(5), nor its federal equivalent (40 CFR 52.21(j)(3)), requires or authorizes the Department to require a BACT determination in this situation, because BACT is only required for "modified" units and the Combination Boiler is not being modified. As shown in Figures 2-2 and 2-3 of the PSD Report (Part B, included as part of the application submittal), the No. 4 Combination Boiler itself will not undergo any physical change or change in the method of operation. The Bark Hog that is being replaced is located in the fuel storage and handling area, upstream of the Boiler. Both EPA and the FDEP have consistently interpreted the PSD rules over the years to require a BACT analysis only for modified equipment. BACT analyses have not been required for emissions units which are "affected" by the project, but which are not being "modified". The relevant history on this issue is presented below.

1. BACT Applies Only to Modified Units

Florida Rule 62-212.400(5)(c) states that a "proposed facility or modification shall apply Best Available Control Technology (BACT) for each pollutant subject to preconstruction review requirements..." The federal equivalent, and the rule upon which the Florida rule was fashioned, is 40 CFR 52.21(j)(3), which reads as follows:

> *"A major modification shall apply best available control technology for each pollutant subject to regulation under the Act for which it would result in a significant net emissions increase at the source.* ***This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit."***

The preamble to this rule elaborates that BACT is required for "...modifications only when a net emissions increase occurs at the changed unit(s) and a significant net emissions increase occurs at the plant; BACT applies only to the units actually modified." (45 FR 52676, August 7, 1980). As explained below, we understand that the Florida rule was intended to parallel, and be no more stringent than, this federal rule upon which it was based.

All written EPA determinations of which we are aware support and corroborate the notion that, while PSD review may require consideration of the emissions increases from affected but unmodified units, BACT only applies to the modified units. Prior Florida determinations and applications of Rule 62-212.400(5) have been consistent with these EPA determinations.

Numerous EPA interpretations have confirmed this position. A June 1981 letter (June 7, 1981 letter from Mr. James Wilburn (Chief, Air Management Branch, EPA Region IV) to Mr. Richard Grusnick (Air Program Director, Alabama Department of Environmental Management)), included in Attachment A, states the following with regard to the application of BACT to non-modified units:

> *"In the situation where the individual boiler being converted is capable of firing coal with minimal physical changes (for example, change of burners only), BACT analysis would apply to the coal handling and storage equipment as well as any other necessary new equipment. BACT analysis would not apply to the boilers since individually they were designed to accommodate coal and therefore will not be undergoing a physical change or change in the method of operation."*

Another memorandum (July 28, 1983 memorandum from Mr. Edward Reich (Director, Air Source Compliance Division, EPA OAQPS) to Mr. Michael Johnston (Chief, Air Operations Section, EPA Region X)) (Attachment B) addresses BACT applicability in the context of a pulp mill that proposed to install a new bleach plant and larger digester, while leaving a recovery furnace unmodified. EPA concluded that BACT did not apply to the recovery furnace:

> *"Since the recovery boiler itself will not be undergoing a physical change or change in the method of operation, it will not have to apply BACT. However, all emissions increases must undergo air quality analysis and will consume applicable air quality increments"*

An undated letter from Gerald Emison to Morton Sterling, apparently drafted in the 1989 to 1990 timeframe, affirms the application of BACT to modified units through the following statement:

> *"Consequently, although the addition of gas firing would subject the source as a whole to a PSD review, the requirement to apply BACT is applicable only to those emissions units at the source which undergo both a physical or operational change and a significant net emissions increase."*

Based on this letter, included in Attachment C, it is clear that EPA and the states have been consistent on the application of BACT only to emissions units that have undergone a physical or operational change.

Also included with this submittal, as Attachment D, is a recent policy statement (dated February 2000) that was issued by the Wisconsin Department of Natural Resources, with the concurrence of EPA Region 5. While written for another state in another EPA region, this letter specifically addresses the history on the application of BACT. This letter reaffirms that the federal PSD regulations do not require the application of BACT to non-modified emissions units.

From the information presented above, it is clear that BACT does not apply to an emissions unit at which there is no physical change or change in the method of operation. Further, under the federal PSD rules, a change in the method of operation specifically excludes increased operating hours and production rates, unless prohibited by a federally enforceable NSR/PSD air construction permit condition that was established after January 6, 1975. (40 CFR 52.21(b)(2)(iii)).[1] Although, actual emissions and actual bark/wood throughput for the No. 4 Combination Boiler may increase, the application did not propose to change any federally enforceable permit conditions for this unit.

The federal PSD rule has consistently been interpreted in this manner by EPA through guidance, memos, applicability determinations and the PSD workshop manual (draft). The only exception that we are aware of is a recent determination for a case where one emissions unit (a power boiler) served as the control device for another emissions unit (pulp mill digesters) undergoing a modification. In that case, EPA determined that the control device (the power boiler) should be considered as part of the same emissions unit. Hence, if the emissions unit required BACT review, then the associated emissions unit serving as the control device was also required to undergo BACT review for those pollutants that would significantly increase as a result of the modification.

This exception does not apply to the Palatka project, as the Combination Boiler does not serve as a control device for the Bark Hog or for any other source in the fuel handling/storage area. As such, this interpretation has no relevance for the project at hand.

The State of Florida rule quoted above was promulgated in the early 1980s, after EPA revised the federal PSD rule.

Unfortunately, the State rule is not as clear as the federal rule. However, Mr. David Buff, P.E., Q.E.P., now of Golder Associates Inc. and P.E. of record for the Bark Hog application, recalls that at the time of adoption of the State rule, there was no intention to be more stringent than the EPA PSD rule. To the contrary, the Department intended that the rule be interpreted and applied in the same manner as the federal rule. This is clear from the fact that an economic impact statement was not prepared by the State of Florida at the time of rule adoption, nor was there review by the Governor and Cabinet, which would have been required if the rule was more stringent than the EPA rule.

Interpretation of the State PSD rule in the manner in which FDEP is now prescribing would result in severe economic impacts, and would likely stifle economic growth. Companies would find PSD too costly or too risky to undertake, and therefore, would not be as likely to undertake expansion projects, efficiency enhancement projects or energy savings projects. Generally, as EPA intended, when an emissions unit is physically modified, or undergoes a change in the method of operation, a capital expenditure is associated with the change. This is the appropriate time to require additional capital expenditure for pollution control purposes, and makes it easier to justify the additional capital and operating costs as part of an expansion project. However, if

[1] An increase in utilization of an affected unit, by itself, cannot be deemed a "change in the method of operation." If it were, then there would be no difference under PSD between "modified" units and "unmodified but affected" units, and BACT would be required for every affected unit (that is, every unit that would undergo a net emission increase of the PSD pollutant) in every debottlenecking situation. Clearly, that has not been the outcome in the long line of EPA determinations on this issue.

BACT requirements are expanded to other emissions units that have no associated capital expenditure, the cost impact is much greater.

The State's definition of modification at Rule 62-210.200(185) is very similar to the federal definition. Specifically, the State definition excludes increases in operating hours or production rates from the term "modification", unless the increase would be prohibited under any federally enforceable NSR/PSD air construction permit condition established after January 6, 1975. Applying this reading directly to the proposed project, the "modification" would not include the emission units which are not being physically modified or for which there is no change in the method of operation (*i.e.,* the No. 4 Combination Boiler).

The State of Florida has for nearly 20 years applied its PSD regulations in a manner consistent with EPA's PSD regulations, guidance and policy. This has set a legal precedent, which now cannot be changed merely by a different interpretation or policy. A formal rule change and economic impact statement would be required. Absent that, such an interpretation constitutes non-rule policy and is invalid under Section 120, Florida Statutes (Florida Administrative Procedures Act).

2. The No. 4 Combination Boiler Is Not Being Modified

In the course of applying the PSD rules, there has always been a distinction between units that are being "modified" and units that are not being modified, but are nonetheless "affected" by modifications elsewhere at the facility. The federal PSD regulations do not define the term "affected facility", a key term in the New Source Performance Standards (NSPS) context. However, they do define the term "emission unit" at 40 CFR 51.165(a)(1)(vii) as, "any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the Act". In reviewing PSD applicability, these definitions become important in identifying the components of a facility that are "modified" and are, thus, subject to PSD permitting and a BACT review. They support the conclusion in this case that the No. 4 Combination Boiler is not being modified as part of the proposed project.

All of the NSPSs for steam generating units (*e.g.,* NSPS Subparts D, Db, and Dc) contain, or are based on, extensive background documentation that clearly and consistently defines the "affected facility". Furthermore, there have been numerous determinations over the years regarding this definition. All of these determinations are consistent in concluding that the fuel handling/feed system is not considered part of the "affected facility".

One of the earliest determinations was issued in July 1980 (letter from Mr. Edward Reich (EPA Director of the Division of Stationary Source Enforcement) to Sandra Gardebring (Director of the Enforcement Division, EPA Region V)) (see Attachment E). This particular review questioned whether modifications of fuel handling and feeding equipment at a Northern State Power Company facility would trigger applicability of NSPS Subpart D. Several statements in the letter are relevant to the project at the Palatka Mill. First, the letter states the following:

> *"It appears that NSP is undergoing an increase in production rate. This would be subject to NSPS if it involves a capital expenditure on the facility, the individual burner. It is thus essential to determine if the components being enlarged, the fuel handling and feeding equipment, are part of the affected facility"*

In a subsequent paragraph, the letter goes on to make the following statement:

"We have been in contact with OAQPS and they have provided general guidance as to what they consider to be the components of the affected facility. Under EPA's BID for proposed Particulate Matter Emission Standards for Electric Utility Steam Generating Units (450/2-78-006a, July 1978) boiler components include burners (pulverizer, crusher, stoker), combustion air system, steam generation system (firebox, tubes) and draft system."

Also of relevance to this issue is the proposed rule for NSPS Subpart Da (see Attachment F). Although this rule applies only to electric utility steam generating units, the following definition of a "steam generating unit" contained in the proposed rule is relevant:

"Steam generating unit...means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included). A steam generating unit includes the following systems: (1) Fuel combustion system (including bunker, coal pulverizer, crusher, stoker, and fuel burners, as applicable)...(2) Combustion air system...(3) Steam generating system (firebox, boiler tubes, etc.)...(4) Draft system (including the stack)."

This language from the proposed Subpart Da rule is consistent with the determination issued in 1980 (reference above). This is also consistent with the Background Information Document (BID) issued as part of Subpart Da for nitrogen oxides standards (EPA-450/2-78-005a, July 1978) (see Attachment G). On Pages 5-3 and 5-4, the BID contemplates the "inlets to the affected facility". In that regard, the BID states the following:

"The major points which define the inlets to the affected facility are...(1) The inlet to the pumps which feed water at steam generator pressure...(2) The inlet to the bins which directly feed the pulverized or stoker systems unless the bins are sized to store more than enough coal to operate the steam generator 72 hours at full load. When large bins are installed, the inlet to the affected facility is the outlet of the bins feeding the pulverizer or stoker systems...(3) The combustion air intakes..."

The BID goes on to define the "outlets of the affected facility" and further states that, *"All components of the steam generator installed between these points are part of the affected facility"*. The BID for the particulate matter standards under Subpart Da (EPA-450/2-78-006a, July 1978) uses substantially the same language in defining the "affected facility".

Following promulgation of the various NSPS for steam generating units, there have been subsequent determinations regarding the definition of an "affected facility". One such determination from February 1987 (letter from Mr. James Wilburn (Chief of the Air Compliance Branch, Air Pesticides and Toxics Management Division, EPA Region IV) to Mr. C.H. Fancy (Deputy Chief, Bureau of Air Quality Management, Florida Department of Environmental Regulation)) again defines the "affected facility" and actually includes a diagram (see Attachment H). The letter states the following:

"As the diagram indicates, the following items are included in the affected facility...boiler and equipment, breaching, draft equipment, lighting systems, oil-burning equipment, pulverized fuel equipment, stoker or equivalent feeding equipment, and pressure oil systems."

The diagram (see Attachment H) clearly shows the fuel storage and handling system to be outside the "affected facility".

Citing the February 1987 determination referenced above, another determination was issued by EPA Region 4 for a Georgia-Pacific building products facility in 1999. This more recent determination (August 1999 letter from R. Douglas Neeley (Chief, Air and Radiation Technology Branch EPA Region 4) to Mr. Jerry Cain (Chief, Environmental Permits Division, Mississippi Department of Environmental Quality)) dealt with the definition of an "affected facility" under NSPS Subpart Dc. This letter, included as Attachment I, states the following with regard to the definition of an "affected facility":

> *"Based upon the definition of a steam generating unit in Subpart Dc, the primary components of the affected facility would be the equipment needed to combust fuel (i.e., burners and combustion chamber), the heat exchanger, and the combustion air supply system...In addition, based upon the enclosed February 13, 1987, EPA determination for a coal-fired boiler, the pumps returning the thermal oil to the heat exchanger would also be part of the affected facility."*

The letter goes on to direct Georgia-Pacific to exclude certain items in its reconstruction calculation, as those items are not considered part of the steam generating unit. Of relevance is the following language in the letter:

> *"...the steam generating unit at GP begins at the inlet to the pump supplying thermal oil to the heat exchanger section of the unit, and equipment such as thermal oil storage tanks upstream of this point are not part of the affected facility...According to EPA's February 13, 1987, determination, the affected facility for a coal-fire boiler begins at the feed water pump inlet and ends at the boiler's steam outlet. Since the thermal oil in GP's boiler is analogous to the boiler feed water in a coal-fired unit, pumps and piping upstream of the last pump at the boiler inlet and downstream of the hot oil exit are not parts of the affected facility."*

It is abundantly clear from the numerous reviews, determinations and rulemakings, that the fuel handling system associated with a steam generating unit is not considered part of the "affected facility" for the purposes of NSPS applicability. This same conclusion should apply for the purposes of PSD applicability.

There is clearly precedent in prior determinations for using these definitions in defining modifications for the purposes of PSD and BACT applicability. One such recent determination (November 2000 letter from Ms. Judith Katz (Director, EPA Air Protection Branch, EPA Region III) to Mr. John Daniel (Director, Air Program Coordination Virginia DEQ)) that specifically deals with the application of BACT, is included in Attachment J. In this determination, for E.I. Du Pont De Nemours and Company, several statements are relevant for the Bark Hog replacement at the Palatka Mill. Notably, on Page 3 of the determination, it is stated that:

> *"An NSPS is one source of information that may be helpful in defining an emission unit for the purpose of evaluating control options."*

In defining the "affected facility" for the purposes of the application of BACT, the determination goes on to state the following:

"Therefore, we think it is appropriate to follow the NSPS in this case."

Finally, the determination closes with the following remark:

"The NSPS definition of emissions unit was relied on because the rule provided a rationale as to why these processes should be grouped together for purposes of setting a unique emission limitation..."

As discussed in detail above, the proposed Bark Hog replacement is a change to the feed and handling system and should not be considered a modification to the Combination Boiler for the purposes of the PSD regulations.

As spelled out in our application, and reiterated above, the Combination Boiler itself is not being modified as a result of the replacement of the Bark Hog. In fact, the Combination Boiler will continue to fire the same fuels and its capacity will not be changed. However, as acknowledged in the application, it is possible that the Boiler could experience an "actual" increase in bark/wood throughput as a result of the Bark Hog project. For this reason, in our application, the Boiler is identified, and treated as an "affected unit" for the purposes of the PSD evaluation.

Summary and Conclusions

In summary, with regard to the Bark Hog replacement, the following facts and conclusions are relevant:

- The Bark Hog replacement is taking place in the Bark Handling System area, only involving fuel handling equipment
- The Bark Handling System is a separate emissions unit at the Palatka Mill, and not part of the No. 4 Combination Boiler – the Bark Hog is a separate piece of equipment that is part of the Bark Handling System, located upstream of the Combination Boiler
- The No. 4 Combination Boiler itself is not undergoing a physical or operational change and it will continue to operate within the federally enforceable conditions that have been established for it in the past.
- EPA, FDEP (in the past) and other states have been consistent in their view that, even if an emissions unit is found to be subject to PSD review as an "affected" source, it is not required to undergo a BACT review.

We appreciate your consideration of this information and we strongly encourage you to withdraw the RAI as it is inappropriate. As stated above, we do not agree with the Department that a BACT review is required for the No. 4 Combination Boiler as part of this permitting exercise. If the Department is not satisfied with our response and reasoning, perhaps a meeting is in order so that we may better understand the regulatory drivers behind the Department's position. In the meantime, please feel free to contact Ms. Myra Carpenter of my staff at (386/329-0918).

Sincerely,

Theodore D Kennedy

Mr. Theodore D. Kennedy
Vice President

Attachments

cc: Tammy Wyles, Scott Matchett, William Jernigan, Dave Buff, Golder & Assoc.

Attachment A
June 7, 1981 Letter – Wilburn to Grusnick

June 7, 1981

4AW-AM

Mr. Richard E. Grusnick
Director, Air Program
Alabama Department of Environmental Management
State Capitol
Montgomery, Alabama 36130

Dear Mr. Grusnick:

This is to inform you of Region IV policy concerning applicability of coal conversions to EPA PSD regulations.

Fuel conversions, in general, are considered major modifications for purposes of PSD review providing emission increases are significant. However, Section 52.21 (b) (2) (iii) (e) provides an exemption for certain fuel conversions from the major modification definition. Specifically, this section exempts a fuel conversion from PSD review if the source was capable of accommodating the alternate fuel before January 6, 1975 and such a change is not prohibited by any enforceable permit conditions.

The question then, is whether the source, i.e., the entire plant, was capable of accommodating coal before January 6, 1975. For purposes of converting one or more, but not all of the boilers, we interpret this provision as requiring that the plant be capable of receiving, transferring, and preparing coal, was then transferring coal and combusting coal in the units being converted, and disposing of the ash. It is not necessary for the plant to be capable of carrying out all those operations for every unit at the source, but only for those being converted. On the other hand, if the plant is capable of receiving coal and transferring and combusting it only in some other unit at the plant, but not the one being converted, the plant would not be deemed capable of accommodating coal for purposes of that project.

In order for a plant to be capable of accommodating coal, the company must show not only that the design (i.e., constructive 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." Thus, a source that had used coal at a particular unit at an earlier time, but later switched to another fuel, would be capable of accommodating coal as long as the coal handling equipment still existed. If coal handling equipment had been removed or was never installed, the source would not be coal accommodative. If a proposed conversion is not eligible for the execution under 52.21 (b) (2) (iii) (e), it is considered a major modification for the purposes of PSD review if the resulting net emission increases are significant. PSD applicability would be based on all emission increases form the conversion, including emission increases from the coal and ash handling and storage facilities as well as from the boilers, since all the increases are caused by the conversion to coal.

Once PSD applicability has been established, it is then necessary to undertake a BACT analysis as required under 52.21 (j). That section, under paragraph 3, requires that a major modification apply "best available control technology for each pollutant subject to regulation under the Act for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit." This section clearly intends that technology review be assessed on an emissions unit rather than on a plant-wide basis.

In the situation where the individual boiler being converted is capable of firing coal with minimal physical changes (for example, change of burners only), BACT analysis would apply to the coal handling and storage equipment as well as any other necessary new equipment. BACT analysis would not apply to the boilers since individually they were designed to accommodate coal and therefore will not be undergoing a physical change or change in the method of operation.

In addition to the BACT analysis, requirements for a source impact analysis (52.21 (k)), air quality analysis (52.21 (m)), additional impact analyses (52.21 (o)), and Class I analysis (52.21 (p)) must be satisfied.

Once the source has satisfied these requirements and the notice and public comment provisions, permit approval may proceed.

Region IV is aware that guidance on this question has been somewhat vague, and possibly conflicting in the past. Therefore, we do not intend for this policy to be applied retroactively where it was not adhered to. However, we do expect each Region IV state to immediately implement this policy for all future applicability determinations.

Sincerely yours,

James T. Wilburn, Chief
Air Management Branch
Air & Waste Management Division

cc: Ed Reich
Darryl Tyler

Attachment B
July 28, 1983 Memorandum – Reich to Johnston

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL 28 1983

OFFICE OF
AIR, NOISE AND RADIATION

SUBJECT: PSD Applicability Pulp and Paper Mill

FROM: Director
Stationary Source Compliance Division
Office of Air Quality Planning and Standards

TO: Michael M. Johnston, Chief
Air Operations Section - Region X

Your request dated July 6, 1983, to Mike Trutna concerning a PSD applicability issue has been forwarded to my office for response. Your request concerns a pulp and paper company that is proposing to install a bleaching plant and a larger digester. While the construction of these units does not by itself cause increased emissions, emissions from the recovery boiler as a result of this construction activity will increase above the significance levels, but remain below the maximum design permit levels. Your question, is whether this a major modification under the PSD requirements.

The PSD rules at 40 CPR 52.21 (b) (2) define major modifications as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act." Net emissions increase is defined as:

> "the amount by which the sum of the following exceeds zero: Any increase in actual emissions from a particular physical change or change in method of operation at a stationary source; and Any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable."

Major modifications are, therefore, determined by examining changes in actual emission levels. Actual emissions are defined as:

"the actual rate of emissions of a pollutant from an emissions unit, as determined in accordance with sub- paragraph (ii)-(iv) below

(ii) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two- year period which precedes the particular date and which is representative of normal source operation. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the units actual operating hours, production rates and types of materials processed, stored, or combusted during the selected time period.

(iii) The Administrator may presume that source specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(iv) For any emissions unit which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date."

Since this source has been in operation for some time, subparagraph (iv) does not apply. Your memo indicates that the recovery boiler is subject to a permit limit. Ray Nye of your staff has informed my staff that this permit limit binds the recovery boiler to a level of 0.1 gr/dscf, but does not provide any discussion on the unit's operating rate. The recovery boiler has operated in the past at a rate of 450 tons/day, consistent with existing digester capacity. Although the regulations provide a presumption for the use of allowable emissions when source specific limits are established, the preamble at 45 FR 52718 (August 7, 1980 states that:

"The presumption that Federally enforceable source specific requirements correctly reflect actual operating conditions should be rejected by EPA or a State, if reliable evidence is available which shows that actual emissions differ from the level established in the SIP or permit."

Therefore, since the recovery boiler could not have operated at a level higher than that provided by the existing digester capacity, any increase in actual emissions at the recovery boiler which will result from the increased capacity provided by the larger digester must be considered for the purposes of PSD applicability.

Once it is determined whether there is a significant net emissions increase (summing the emission increases from the larger digester, new bleaching plant and the increased operation of the recovery boiler) in conjunction with any contemporaneous emission increases and decreases, the PSD requirements should be applied, including BACT and air quality analyses. The regulations at 40 CFR 52.21(j)(3) require that:

> "A major modification shall apply best available control technology for each pollutant subject to regulation under the Act for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit."

Since the recovery boiler itself will not be undergoing a physical change or change in the method of operation, it will not have to apply BACT. However, all emissions increases must undergo air quality analysis and will consume applicable air quality increments.

This response has been prepared with the concurrence of OGC and CPDD. Should you have any questions concerning it, please contact Rich Biondi at 382-2831.

Edward E. Reich

cc: Mike Trutna
Peter Wyckoff
Dave Rochlin

Attachment C
1989/1990 (Not Dated) Letter – Emison to Sterling

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

Mr. Morton Sterling, Director
Environmental Protection
Detroit Edison Company
200 Second Avenue, 482
Detroit, Michigan 48226

Dear Mr. Sterling:

This is a followup to the October 19, 1989 meeting during which Detroit Edison further discussed its position that the addition of natural gas firing capacity to the Greenwood Unit I Power Plant should not be subject to a prevention of significant deterioration (PSD) review. At the meeting, you requested that Environmental Protection Agency (EPA) Headquarters review Region V's previous determination that the proposed fuel conversion was a "major modification" for PSD purposes.

As you are aware, in a letter dated December 20, 1988, EPA Region V concluded that the proposed conversion of the oil-fired Greenwood Unit to dual capacity for oil and gas firing would subject the plant to a PSD review for nitrogen oxides (NOx). The Region's conclusion was based on a determination that 1) the source was not capable of firing natural gas prior to January 6, 1975 (and therefore was not covered by the PSD exemption for modifications under 40 CFR 52.21(b)(2)(iii)(e)(1)); and 2) there wou ld be a significant net increase of NOx resulting from the change. As you have requested, we have reevaluated this finding in light of the additional information submitted by Detroit Edison during the October 19 meeting.

The information presented by Detroit Edison indicates that the emissions unit at the source was initially designed and permitted to fire both oil and gas. However, there is no evidence to demonstrate that the source as a whole had, or at any time initiated construction on, the equipment necessary to deliver natural gas to the combustion unit. Without such equipment, it would not be possible for the source to utilize natural gas as an alternate fuel. Consequently, it is our view that the source was not capable of accommodating natural gas prior to January 6, 1975. Therefore, the changes necessary to accommodate the firing of natural gas at the Greenwood Plant would, for PSD purposes, be considered a "physical change" to the source.

As requested, we have also evaluated the net emissions change at the source that would result from the modification. It is Detroit Edison's position that the large decreases in "allowable" emissions of sulfur dioxide, particulate matter, and NOx when burning natural gas rather than oil as a result of the modification, warrants special consideration. Specifically, Detroit Edison feels that the use of a cleaner fuel at the Greenwood Plant warrants a finding that there is no increase in actual emissions and accordingly no "major modification."

Under the PSD regulation, a "major modification" occurs when the physical or operational change at the source (in this case the installation of natural gas handling facilities and the firing of natural gas) would result in a significant net emissions increase for any regulated pollutant at the source. Whether the proposed use of natural gas at the Greenwood Plant would result in a "significant net emissions increase" depends on a comparison between the "actual emissions" before and after the physical or operational change. Where, as here, the source has not yet begun operations firing natural gas, "actual emissions" after the change to natural gas firing are deemed to be the source's "potential to emit" for that fuel [see 40 CFR 52.21(b)(21)(iv)]. Potential annual NOx emissions when firing natural gas at the Greenwood Plant greatly exceed its current actual emissions. Therefore, as a result of the ability to fire natural gas after the change, the emissions of NOx at the source would experience a "signi ficant net emissions increase," within the meaning of the PSD regulations. The fact that current annual "allowable emissions" for the Greenwood Plant when firing oil may greatly exceed future allowable (or potential) emissions when firing natural gas is not relevant for PSD applicability purposes. See Puerto Rican Cement Co., Inc. v. EPA No.89-1070 (First Circuit) (slip op. October 31, 1989).

In summary, our review indicates that Region V correctly applied the PSD applicability criteria.

The PSD requirements include an air quality and additional impact analysis and the application of best available control technology (BACT). The BACT requirement applies to "each proposed emissions unit at which a net emissions increase would occur as a result of a physical change or change in the method of operation in the unit" [see 52.21(j)(3)]. Consequently, although the addition of gas firing would subject the source as a whole to a PSD review, the requirement to apply BACT is applicable only to those emissions units at the source which undergo both a physical or operational change and a significant net emissions increase. It appears that the only emissions unit at the Greenwood Plant affected by the proposal to fire gas would be the existing boiler. Historically, it has been EPA's policy that where the individual boiler being converted is capable of accommodating the alternate fuel, BACT would not apply.

In this case, in addition to the physical changes at the source necessary to deliver natural gas to the existing boiler, a number of canes capable of burning natural gas would be installed in the existing burner assemblies. Modifications to the unit's overfired air duct are also planned. We also understand that there will be no changes in the present oil burning system, which will be retained.

Our review indicates that, by itself, the addition of gas canes to the burners is not a physical change or change in the method of operation in the unit and, consequently, would not subject the boiler to a BACT review. Therefore, if the sole change to the boiler is the addition of the canes, then, in this case, the only requirements necessary for a PSD permit are an air quality analysis, additional impacts analyses, and (if applicable) a Class I impact analysis -- the application of BACT is not required. However, the information submitted by Detroit Edison indicates that changes to the boiler's overfired air duct are also planned. At this time, without additional information on the nature and scope of the work to be done on the overfired air duct, we cannot determine whether these are physical or operational changes to the boiler that are necessary to make the boiler capable of accommodating natural gas. If the ducting work is necessary for this purpose, then a BACT analysis would likely be required.

In addition, it is unclear from the information submitted whether Detroit Edison plans to undertake further modifications to the boiler which would allow 100 percent load when firing natural gas. Currently, the unit as presently configured has the potential of achieving only 75 percent load when firing natural gas. To achieve a higher load, substantial modifications to the unit apparently would be required. These types of physical changes to the boiler likely would require a full PSD review, including a BACT analysis for the boiler. The BACT analysis would require that the source evaluate the use of all available additional air pollution controls for reducing NOx emissions. The analysis would consider retrofit costs for add-on controls and the fact that gas is a relatively clean-burning fuel. Consequently, in this case, it is possible that the currently planned use of a low-NOx burner design may be BACT for gas firing. However, such a conclusion would have to be demonstrated through the requisite BACT analysis. I have asked Region V to work with you should you need assistance in preparing the analysis.

Sincerely,

Gerald A. Emison
Director
Office of Air Quality Planning
and Standards

cc: J. Calcagni, EPA/AQMD
D. Kee, EPA/Region V
G. Foote, EPA/OGC

Attachment D
Wisconsin DNR Policy on Application of BACT for Non-Modified Units

State of Wisconsin \ DEPARTMENT OF NATURAL RESOURCES

WISCONSIN DEPT. OF NATURAL RESOURCES

Tommy G. Thompson, Governor
George E. Meyer, Secretary

101 S. Webster St.
Box 7921
Madison, Wisconsin 53707-7921
Telephone 608-266-2621
FAX 608-267-3579
TDD 608-267-6897

February 23, 2000

Patrick K. Stevens
Director, Environmental Policy
Wisconsin Manufacturers and Commerce
501 East Washington Avenue
P.O. Box 352
Madison, WI 53701-0352

Subject: Application of Best Available Control Technology During Debottlenecking

Dear Mr. Stevens:

On October 29, 1999 I wrote to inform you how the department would address the questions raised in your letter to me of October 12, 1999. Your October 12, 1999 letter had presented questions some of your members had raised regarding the addressing of best available control technology (BACT) during a Prevention of Significant Deterioration (PSD) permitting analysis. As I had informed you on October 29, 1999, the Department would prepare its conclusions on the matters and then seek concurrence from USEPA prior to responding directly to the issues you have raised. As you are aware, the department's opinion was sent to Robert Miller of USEPA Region 5 on November 12, 1999. On February 14, 2000, the department received Mr. Miller's responses to the inquiry, and the department can now respond to your questions. I have attached the USEPA Region 5 response for your reference.

You had presented three hypothetical scenarios and inquired how the department would assess PSD applicability to each. Common to each of the three scenarios was an existing process line at a major stationary source that utilizes steam provided by an on-site power boiler. A physical change has been proposed to be made to the process line that will result in a net emission increase from the process line. The change will require an increase in the amount of steam that is provided to the process line by the power boiler. No physical change to the power boiler is necessary. The process line in this discussion clearly bottlenecks the power boiler's capabilities. Your letter had presented different variations on this theme that I will address below.

Scenario 1:

The net emission increase from the process line will exceed PSD significant thresholds. The net emission increase from the power boiler on a future potential to past actual emission basis also exceeds PSD significant thresholds. However, the increase in emissions on a predicted future actual to past actual emission basis from the power boiler do not exceed the PSD significant thresholds.

Scenario 2:

The net emission increase from the process line will exceed PSD significant thresholds. The net emission increase from the power boiler on a future potential to past actual emission basis also exceeds the PSD significant thresholds, as does the increase in emissions on a predicted future actual to past actual basis.

Scenario 3:

The net emission increase from the process line will not exceed PSD significant thresholds. The net emission increase from the power boiler on a future potential to past actual emission basis exceeds the PSD significant thresholds, however the increase in emissions on a predicted future actual to past actual emission basis does not.

Section NR 405.02(21), Wis. Adm. Code defines major modifications as "any physical change or change in the method of operation of a major stationary source that would result in a significant net emission increase of any pollutant subject to regulation under the act". Section NR 405.02(24)(a), Wis. Adm. Code defines a net emission increase as "the amount by which the sum of the following exceeds zero: Any increase in actual emissions from a particular physical change or change in the method of operation at a stationary source; and any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable". Because these definitions require an examination of "any increases in actual emissions resulting from a particular physical change", all increases in actual emissions at the source resulting from proposed physical change to the process must be included in determining the net emission increase of the project. Thus, <u>increases in actual emissions from the power boiler, due to the relief on the bottleneck provided by the process, must be included in the net emission increase determination.</u>

Section NR 405.02(1), Wis. Adm. Code defines actual emissions as "the actual rate of emissions of a pollutant from an emissions unit, as determined in accordance with (a) through" (c) below:

(a) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and which is representative of normal operation of the source. The department shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(b) The department may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit unless reliable data are available which demonstrate that the actual emissions are different than the source-specific allowable emissions.

(c) For any emissions unit other than an electric utility steam generating unit, which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

Because the emissions units presented in the above scenarios are assumed to have begun normal operations under current conditions, actual emissions prior to the proposed project are determined using the procedures within (a) above. However, since the process and the power boiler have not begun normal operations under the proposed conditions, actual emission after modification are equal to the potential to emit of the units, per (c) above. Thus, the potential actual emissions to past actual emissions determinations offered in these scenarios are irrelevant.

The above discussion leads the department to the conclusion that each of the three scenarios would be considered a major modification and subject to PSD review since the net emission increase from the project (process line increase plus power boiler increases) in each of the three scenarios is considered significant. It is worth noting, especially for Scenario 3, that a source could commit to enforceable emission limits in a permit to ensure that its potential emissions remain below the significance level.

Section NR 405.08(3), Wis. Adm. Code states that "a major modification shall apply best available control technology for air contaminant for which it would result in a significant net emission increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit". The preamble to the August 7, 1980 Federal PSD rule making discusses the application of BACT at Item L, contained on page 52681 of the rule making. Item L states that BACT is required for "modifications only when a net emissions increase occurs at the changed unit(s) and a significant net emissions increase occurs at the plant; BACT applies only to the units actually modified". This requirement, along with its explanatory language, leads the department to the conclusion that since only the process equipment is actually being modified and that the power boiler will not be undergoing any physical or operational changes, BACT must be applied to the process equipment only, and is not required to be applied to the power boiler.

USEPA Region 5 has concurred with the conclusions the department has formed on these hypothetical scenarios. However, we caution you that this response is how the program would address these types of situations in general and that there may be other factors that may present themselves when real life situations occur. Although the department has come to the conclusions outlined above for these generalized scenarios, more specific situations may result in conclusions which differ somewhat from that outlined above, as specific facts surrounding a particular modification are critical in making a BACT applicability determination. Therefore, I caution the careful use of this letter as a reply to a general PSD permit programmatic issue.

Should you require any follow-up regarding this issue, please contact Jeffrey Hanson of my staff at (608) 266-6876.

Sincerely,

Lloyd L. Eagan, Director
Bureau of Air Management

Enclosure

Attachment E
July 7, 1980 Memorandum – Reich to Gardebring

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

JUL 7 1980

MEMORANDUM

SUBJECT: Applicability of PSD and NSPS to Northern States Power Company

FROM: Director
Division of Stationary Source Enforcement

TO: Sandra Gardebring, Director
Enforcement Division, Region V

This is in response to yourMay 29, 1980 memo concerning Northern States Power Company (NSP). You requested a determination as to whether modifications proposed for units 1, 2, 3, and 4 at Black Dog generating plant and units 3, 4, 5 and 6 at High Bridge generating plant would subject the units to NSPS and the generating plants to PSD requirements. This response is based on the information presented in the attachment to your letter, and on the information obtained during a June 19 ,1980 phone conversation between Robert Myers of my staff and Joseph Bizzano, Jr., of NSP.

The original design fuel for these units was 100% high sulfur, high Btu Illinois coal. To comply with the state's sulfur-in-fuel requirement, NSP in the early 1970's shifted to burning a blend of 70% low sulfur, low Btu Montana coal and 30% Illinois coal. Because of the limitations in the capacity of the fuel handling and feeding equipment, NSP has since been unable to burn enough of the blended coal to achieve the same level of steam/electricity production as it enjoyed when it burned 100% Illinois coal.

The company is studying a program of modifications to restore the derate the boilers currently are experiencing. The modifications principally involve the enlargement of the fuel handling and feeding equipment to each boiler so that the original output of steam/electricity can once again be attained. This will result in SO_2 emissions increases of well above 100 tons per year at each plant. NSP reports that particulate emissions will increase as well, however, there is no indication as to the effect the modification will have on NOx emissions. The issue is whether NSPS or PSD requirements would apply to this proposed modification.

Under NSPS a modification is defined at 40 CFR 60.2(h) as "any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted". This is limited somewhat by 40 CFR 60.14(e)(2), as revised July 1, 1979, which states that an increase in production rate of an existing facility is not considered a modification if that increase can be accomplished without a capital expenditure on that facility. Capital expenditure is defined at 45 FR 5617, 40 CFR 60.2(bb) (January 23, 1980) and means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable IRS asset guideline and the existing facility's basis as defined in the IR code.

It appears that NSP is undergoing an increase in production rate. This would be subject to NSPS if it involves a capital expenditure on the facility, the individual boiler. It is thus essential to determine if the components being enlarged, the fuel handling and feeding equipment, are part of the affected facility.

We have been in contact with OAQPS and they have provided general guidance as to what they consider to be the components of the affected facility. Under EPA's BID for proposed Particulate Matter Emission Standards from Electric Utility Steam Generating Units (450/2-78-006a, July 1978) boiler components include burners (pulverizer, crusher, stoker), combustion air system, steam generation system (firebox, tubes) and draft system.

Joseph Bizzano mentioned to Robert Myers, that the ,changes being considered include changing the superheater spacing, adding soot blowers to the boiler, and increasing pulverizer size. Since the superheater and pulverizer are considered part of the affected facility, replacement or redesign which would change the physical characteristics of these components may be a case where modification provisions apply. A final decision must await a complete description by NSP of the specific changes to be made and equipment involved.

For purposes of PSD applicability during the period of the February 5, 1980 stay (45 FR 7800), major modification is determined by a source's potential to emit under both the September 5, 1979 (44 FR 51924) proposed PSD regulations and the June 19, 1978 (43 FR 26388) regulations. Major modification considers changes over the entire source, the generating plant, rather than changes for each boiler.

Under the June 19, 1978 regulations major modification is defined as any physical change in, change in the method of operation of, or addition to a stationary source which increases the potential emission rate (regardless of any emissions reduction achieved elsewhere in the source) of any air pollutant regulated under the Act by 100 tons per year for fossil fuel-fired boilers totaling over 250 mm Btu per hour heat input. Potential to emit means the capability at maximum capacity unless otherwise limited by an enforceable permit condition (43 FR 26404), to emit a pollutant in the absence of air pollution control equipment.

Under the September 5, 1979 proposed PSD regulations, potential to emit is the capability at maximum design capacity to emit a pollutant after the application of air pollution control equipment. Major modification is defined as any physical change in or change in the method of operation of a major stationary source, or series of contemporaneous physical changes in or changes in the method of operation of a major stationary source that would result in a significant net increase in that source's potential to emit the pollutant for which the stationary source is major. For SO_2 and particulate matter ten tons was proposed to be a significant net increase.

Under the June 19, 1978 regulations (43 FR 26404) and the September 5, 1979 proposal, (44 FR 51948) potential to emit includes enforceable permit conditions on the type of materials combusted or processed. Thus, for the two generating plants in question, potential to emit would include Minnesota's sulfur-in-fuel requirement under both definitions.

Generating potential emissions is limited by the quantity of fuel the source is capable of combusting. The ability of the generating plants to combust additional fuel subsequent to the modification results in increased emissions. Since the generating plants were not capable of accommodating this additional fuel without changes to the fuel handling and feeding equipment, this would represent an increase in the potential to emit. NSP would be subject to PSD review if the changes would result in an increase of 100 tons per year of uncontrolled SO_2 or particulate matter emissions and 10 tons per year of controlled emissions. The June 18, 1978 regulations would be applied. This determination assumes that the sources in question are located in attainment or unclassified areas and that no additional controls will be added to the sources to offset any emission increase.

The final PSD regulations are expected to be promulgated before the end of this month. If the proposed modifications of the sources in question take place after promulgation, the new regulations will apply (providing the sources cannot be "grandfathered"). Under the lastest draft of these regulations, a source must have an increase of 40 tons of particulate or SO_2 controlled emissions in order to be subject to PSD review. These regulations also allow a source's potential to emit to include enforceable limitations on hours of operation or type or amount of material combusted or processed.

This response was prepared in conjunction with the Office of Air Quality Planning and Standards and the Office of General Counsel, if you have any questions concerning this determination, please contact either Robert Myers or Janet Littlejohn of my staff, at FTS 755-2564.

Edward E. Reich

cc: Peter Kelly
Peter Wyckoff
Earl Salo
Dave Patrick
Walt Stevenson
Jim Weigold

Attachment F
Proposed Rule, NSPS Subpart Da – September 19, 1978

federal register

TUESDAY, SEPTEMBER 19, 1978
PART V

ENVIRONMENTAL PROTECTION AGENCY

proposed rule
Subpart Da

ELECTRIC UTILITY STEAM GENERATING UNITS

Proposed Standards of Performance and Announcement of Public Hearing on Proposed Standards

BEST AVAILABLE COPY

tives of alternative methods, enforceability, and improvements in emission control technology.

Executive Order 12044, dated March 24, 1978, whose objective is to improve Government regulations, requires executive branch agencies to prepare regulatory analyses for regulations that may have major economic consequences. The proposed standards meet the criteria for preparation of a regulatory analysis as outlined in this Executive order. Therefore, a regulatory analysis has been prepared as required. The analysis is contained in the background information documents for the proposed standards. The regulatory analysis is not being published as a separate document because the work was begun before the President's Executive order was published. However, in order to present a better understanding of the analyses contained in the background information documents, a summary of the analyses is included in the preamble. The summary discusses in detail the alternatives considered.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for revisions determined by the Administrator to be substantial. The Administrator has determined that the proposed amendments are substantial and has prepared an economic impact assessment and included the required information in the background information documents.

Dated: September 11, 1978.

Douglas M. Costle,
Administrator.

It is proposed that 40 CFR Part 60 be amended by revising the heading and § 60.40 of Subpart D, by adding a new Subpart Da, by adding a new reference method to Appendix A, and by reserving Appendix E as follows:

1. The heading for Subpart D is revised to read as follows:

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators Constructed After August 17, 1971

2. Section 60.40 is amended by adding paragraph (a)(3) as follows:

§ 60.40 Applicability and designation of affected facility.

(a) * * *

(3) Is not subject to the provisions of Subpart Da.

* * * * *

(Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)).)

3. A new Subpart Da is added as follows:

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978

Sec.
60.40a Applicability and designation of affected facility.
60.41a Definitions.
60.42a Standard for particulate matter.
60.43a Standard for sulfur dioxide.
60.44a Standard for nitrogen oxides.
60.45a Commercial demonstration permit.
60.46a Compliance provisions.
60.47a Emission monitoring.
60.48a Compliance determination procedures and methods.
60.49a Reporting requirements.

Authority: Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978

§ 60.40a Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) Which is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) This subpart applies to electric utility combined cycle gas turbines that are capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fossil fuel in the steam generator are subject to this subpart. (The gas turbine emissions are subject to Subpart GG.)

§ 60.41a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Steam generating unit" means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included). A steam generating unit includes the following systems:

(1) Fuel combustion system (including bunker, coal pulverizer, crusher, stoker, and fuel burners, as applicable).

(2) Combustion air system.

(3) Steam generating system (firebox, boiler tubes, etc.).

(4) Draft system (excluding the stack).

(b) "Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its maximum design electrical output capacity to an electrical distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

(c) "Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

(d) "Subbituminous coal" means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-66.

(e) "Lignite" means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-66.

(f) "Coal refuse" means waste products from coal mining, physical coal cleaning, and coal refining operations (e.g. culm, gob, or other rejects) containing coal, ash matrix material, clay, and organic and inorganic material.

(g) "Potential combustion concentration" means the theoretical emissions (ng/J, lb/million Btu) that would result from combustion of a fuel in an uncleaned state (without emission control systems) and:

(1) For particulate matter is:

(i) 3,000 ng/J heat input (7.0 lb/million Btu) for solid fuel; and

(ii) 75 ng/J heat input (0.17 lb/million Btu) for liquid fuels.

(2) For sulfur dioxide is determined under § 60.48a(b).

(3) For nitrogen oxides is:

(i) 290 ng/J heat input (0.67 lb/million Btu) for gaseous fuels;

(ii) 310 ng/J heat input (0.72 lb/million Btu) for liquid fuels; and

(iii) 990 ng/J heat input (2.3 lb/million Btu) for solid fuels.

(h) "Combined cycle gas turbine" means a stationary gas turbine system where heat is recovered from the exhaust gases by passing the exhaust gases through a steam generating unit. Fossil fuel may also be combusted in the steam generating unit.

(i) "Utility company" means the largest organization, business, or governmental entity that owns the affected facility (e.g. a holding company with operating subsidiary companies).

(j) "System capacity" means the sum of the rated electrical output capacity of all electric generating equip-

EPA4PER015491

Attachment G
Background Information Document – Subpart Da, Background Information for ProposedNO_x Emission Standards

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-450/2-78-005a
July 1978

Air

EPA

Electric Utility Steam Generating Units

Background Information for Proposed NO_x Emission Standards

NSPS

Emission increases are allowed if such increases are caused by routine maintenance, repair, and replacement. Emission increases are also allowed if caused by increases in production rate which can be accomplished without major capital expenditure. Increases in emissions caused by longer operating hours are also exempted from the rule on no emission increase. Another exemption is for the use of an alternative fuel or raw material if--prior to the date any standard becomes applicable--the existing facility was designed to accommodate that alternative use. Conversion to coal as stipulated in Section 111(a)(8) of the Clean Air Amendments of 1977 is not considered a modification. Emission increases caused by the addition or use of any system whose primary function is the reduction of air pollutants, are also exempt from the no emission increase rule.

5.2.2 Modified Pulverized Coal-Fired Steam Generators

For the purposes of determining if modification regulations apply or should apply, the pulverized coal-fired steam generator system is defined as including the following major components.

a) pulverizer system

b) combustion air system

c) steam generation system

d) draft system

e) fuel combustion system

The major points which define the inlets to the affected facility are:

1. The inlet to the pumps which feed water at steam generator pressure.
2. The inlet to the bins which directly feed the pulverized or stoker systems unless the bins are sized to store more than enoug coal to operate the steam generator 72 hours at full load. When large bins are installed, the inlet to the affected facility is t outlet of the bins feeding the pulverizer or stoker systems.
3. The combustion air intakes.

The major points which define the outlets of the affected facility ar

1. Any steam outlet
2. Any bottom ash outlet
3. The outlet of the last system installed before the stack, such as the outlet of any induced draft fan.

All components of the steam generator installed between these points are part of the affected facility except any air pollution control systems, suc as electrostatic precipitators, mechanical collectors, baghouses, or scrubbers.

Replacement of the pulverizer system with a similar system or replacement of component parts of the pulverizer system with similar ~~parts would not be considered a modified source.~~ However, replacement or redesign of the pulverizer system which would substantially change the physical characteristics of the pulverized coal may be a change where modification regulations apply.

Likewise changes in the design of the combustion air system which change the way combustion air is introduced to the combustion chamber would cause a source to be evaluated to determine if modification regulations should apply. Changing the combustion air damper settings is not a modification as long as no redesign of the combustion air system is involved.

The steam generation system includes the feedwater treatment system, watertubes, economizer, and superheat and reheat sections. Maintenance of these components is not a modification. Major redesign of these parts would cause a source to be evaluated to determine if modification regulations should apply. It is doubtful that redesign of the feedwater treatment system, the economizer, or the superheat or reheat sections would affect NO_x emissions. Redesign of the steam generation system components which affect combustion temperatures--such as the waterwall sections--could change NO_x emission characteristics.

Redesign of the draft system such as changing from induced draft conditions to pressurized firing conditions would cause a source to be evaluated to determine if modification regulations should apply.

Changes in the fuel combustion system which would be modifications are:

a) changes in the number of burners

b) changes in the type of burners

and c) changes in the location of burners.

Although a change to a different nitrogen content or a different moisture content coal or a switch from lignite to non-lignite coal might be considered a modification, these changes are exempted from modification evaluation by current regulations.[1]

Sources, which by reason of the date of new construction, are subject to the NO_x new source performance standard for coal combustion continue to be subject to the original standard in spite of any subsequent changes in solid fossil fuels or alteration. In cases where the original NO_x standard is revised to become more restrictive, none of the foregoing discussed modifications should cause the source regulated by the original NO_x standard to become subject to the more restrictive standard unless the modifications are so extensive as to be classed as reconstruction. (See Section 5.3).

5.2.3 Modification of Oil- or Gas-Fired Steam Generators to Fire Coal

The discussion of Section 5.2.3 is limited to modifications which would cause a source to become subject to NO_x new source performance standard modification regulations for large pulverized coal (other than lignite)-fired steam generators.

Alterations which might cause an existing oil or gas-fired steam generator to become subject to NO_x modification regulations for coal-fired steam generators are alterations involving a switch from gas or oil to coal. Current regulations provide that if the oil or gas-fired source is already designed to fire coal, a switch to coal does not cause the source to become subject to coal-fired steam generator NO_x modification regulations. In addition, Section 111(a)(8) of the Clean Air Amendments of 1977 exempts from the modification provisions of the

Attachment H
February 13, 1987 Letter – Wilburn to Fancy

FEB 18 1987

4APT-AC

Mr. C. H. Fancy
Deputy Chief
Bureau of Air Quality Management
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301

Dear Mr. Fancy:

This letter is in response to your letter of July 11, 1986, to Mr. Bruce Miller concerning interpretation of the reconstruction provisions under 40 CFR 60.15. I apologize for the amount of time it has taken to answer your letter, however, analysis of the forty-seven (47) items presented by the Florida Electric Power Coordinating Group (FEPCG), which were enclosed with your letter, required considerably more time than originally anticipated.

Section 60.15 of the New Source Performance Standards (NSPS) specifies that reconstruction occurs if the fixed capital cost of the new components exceeds 50% of the fixed capital cost of a comparable entirely new facility, and if it is technologically and economically feasible for the facility to comply with the applicable NSPS. As cited in FEPCG's summary, the December 16, 1975, preamble to the construction regulations defines fixed capital cost as the capital needed to provide all the depreciable components, including the costs of engineering, purchase and installation of major process equipment, contractor fees, instrumentation, auxiliary facilities, buildings and structures. Costs associated with the purchase and installation of air pollution control equipment are only included in the fixed capital cost to the extent that the equipment is required as part of the manufacturing/operating process. When determining reconstruction costs, care should be exercised to include only those costs associated with the reconstructed affected facility.

FEPCG has proposed a list of specific items to be included in the reconstruction costs for fossil-fuel-fired steam electric generating units. The list is composed of the accounting categories provided in the Federal Energy Regulatory Commission regulation at 18 CFR Part 101. We have reviewed this list and have determined that a substantial number of the items are not appropriate for inclusion in the cost analysis. Only the costs of items included in, and activities associated with, the affected facility are to be included in the reconstruction costs. The affected facility for fossil-fuel-fired steam electric plants consists only of the steam generating unit as defined at 40 CFR 60.40a and §60.41a. The affected facility is more specifically described at §60.41a in the proposed standards (Attachment A), and the July 1978 Background Information Document (Attachment B).

Section 60.41a(a) of the proposed standards for electric utility steam generating units elaborates on the definition of steam generating unit: "... A steam generating unit includes the following systems: (1) Fuel combustion system (including bunker, coal pulverizer, crusher, stoker, and fuel burners, as applicable). (2) Combustion air system. (3) Steam generating system (firebox, boiler tubes, etc.). (4) Draft system (excluding the stack)." The affected facility then starts at the coal bunkers, and ends at the stack breeching.

The units which constitute the affected facility may best be conveyed by the diagram in Attachment C. As the diagram indicates, the following items are included in the affected facility: boiler and equipment, breaching, draft equipment, lighting systems, oil-burning equipment, pulverized fuel equipment, stoker or equivalent feeding equipment, and pressure oil systems. The following equipment would only be included in reconstruction costs to the extent that they directly service the boiler: foundations and structural steel, buildings, ash handling equipment (generally only the discharge valves to the ash hopper), boiler feed water system, coal handling and storage equipment (only the coal bunker and pulverizer), instruments and devices, ventilating equipment, wood fuel equipment (wood chipper), circulating pumps (just at the boiler), cooling system, fire extinguishing systems, mechanical meters, platforms, railings, steps, gratings, and steelwork. Likewise, engineering, purchase cost, installation, and contractor fees should be included only to the extent that they are associated with reconstruction of affected process equipment (the steam generating unit).

Many of the items included in FEPCG's proposed list are not part of the affected facility and should not, therefore, be included in reconstruction costs. These items are as follows: land, site preparation, demolition, boiler plant cranes, stacks, station piping, water purification equipment, water-supply systems, air cleaning and cooling apparatus, condensers, generator hydrogen, cranes and hoists, excitation systems identified with the main generating units, foundations and settings for turbogenerator, governors, lubricating systems, main exhaust and main steam piping, throttle and inlet valve, intake and discharge tunnels, turbogenerators, water screens, motors, and moisture separator for turbine steam. Auxiliary boilers should also be excluded from reconstruction cost calculations. We agree with you that the costs of land and site preparation should not be included in reconstruction costs. Land, site preparation, and demolition are not depreciable components as defined by fixed capital cost. Also, land, unlike process equipment, is not a component of the affected facility that need be or could be replaced.

Although it appears we have provided specific guidance in response to the PEPCG inquiry, our evaluation is based on very general information and we recommend determination of reconstruction costs on a case-by-case basis in accordance with 40 CFR 60.15.

If you have any questions concerning this letter, please contact Brian Beals of my staff at 404/347-2904.

Sincerely yours,

James T. Wilburn, Chief
Air Compliance Branch
Air, Pesticides, and Toxics
Management Division

Enclosure

bc: Dick DuBose

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ATTACHMENT A

federal register

TUESDAY, SEPTEMBER 19, 1978
PART V

ENVIRONMENTAL PROTECTION AGENCY

ELECTRIC UTILITY STEAM GENERATING UNITS

Proposed Standards of Performance and Announcement of Public Hearing on Proposed Standards

EPA4PER015490

tance of alternative methods, enforceability, and improvements in emission control technology.

Executive Order 12044, dated March 24, 1978, whose objective is to improve Government regulations, requires executive branch agencies to prepare regulatory analyses for regulations that may have major economic consequences. The proposed standards meet the criteria for preparation of a regulatory analysis as outlined in this Executive order. Therefore, a regulatory analysis has been prepared as required. The analysis is contained in the background information documents for the proposed standards. The regulatory analysis is not being published as a separate document because the work was begun before the President's Executive order was published. However, in order to present a better understanding of the analyses contained in the background information documents, a summary of the analyses is included in the preamble. The summary discusses in detail the alternatives considered.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for revisions determined by the Administrator to be substantial. The Administrator has determined that the proposed amendments are substantial and has prepared an economic impact assessment and included the required information in the background information documents.

Dated: September 11, 1978.

DOUGLAS M. COSTLE,
Administrator.

It is proposed that 40 CFR Part 60 be amended by revising the heading and § 60.40 of Subpart D, by adding a new Subpart Da, by adding a new reference method to Appendix A, and by reserving Appendix E as follows:

1. The heading for Subpart D is revised to read as follows:

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators Constructed After August 17, 1971

2. Section 60.40 is amended by adding paragraph (a)(3) as follows:

§ 60.40 Applicability and designation of affected facility.

(a) * * *

(3) Is not subject to the provisions of Subpart Da.

* * * * *

(Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)).)

3. A new Subpart Da is added as follows:

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

AUTHORITY: Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978

§ 60.40a Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) Which is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) This subpart applies to electric utility combined cycle gas turbines that are capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fossil fuel in the steam generator are subject to this subpart. (The gas turbine emissions are subject to Subpart GG.)

§ 60.41a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Steam generating unit" means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included). A steam generating unit includes the following systems:

(1) Fuel combustion system (including bunker, coal pulverizer, crusher, stoker, and fuel burners, as applicable).

(2) Combustion air system.

(3) Steam generating system (firebox, boiler tubes, etc.).

(4) Draft system (excluding the stack).

(b) "Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its maximum design electrical output capacity to an electrical distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

(c) "Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

(d) "Subbituminous coal" means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-66.

(e) "Lignite" means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-66.

(f) "Coal refuse" means waste products from coal mining, physical coal cleaning, and coal refining operations (e.g., culm, gob, or other rejects) containing coal, ash matrix material, clay, and organic and inorganic material.

(g) "Potential combustion concentration" means the theoretical emissions (ng/J, lb/million Btu) that would result from combustion of a fuel in an uncleaned state (without emission control systems) and:

(1) For particulate matter is:

(i) 3,000 ng/J heat input (7.0 lb/million Btu) for solid fuel; and

(ii) 75 ng/J heat input (0.17 lb/million Btu) for liquid fuels.

(2) For sulfur dioxide is determined under § 60.48a(b).

(3) For nitrogen oxides is:

(i) 290 ng/J heat input (0.67 lb/million Btu) for gaseous fuels;

(ii) 310 ng/J heat input (0.72 lb/million Btu) for liquid fuels; and

(iii) 990 ng/J heat input (2.3 lb/million Btu) for solid fuels.

(h) "Combined cycle gas turbine" means a stationary gas turbine system where heat is recovered from the exhaust gases by passing the exhaust gases through a steam generating unit. Fossil fuel may also be combusted in the steam generating unit.

(i) "Utility company" means the largest organization, business, or governmental entity that owns the affected facility (e.g., a holding company with operating subsidiary companies).

(j) "System capacity" means the sum of the rated electrical output capacity of all electric generating equip-

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United States Environmental Protection Agency
Office of Air Quality Planning and Standards Research Triangle Park NC 27711
EPA-450/2-78-005a
July 1978

ATTACHMENT B

Air

Electric Utility Steam Generating Units

Background Information for Proposed NO_x Emission Standards

NSPS

EPA4PER015492

Emission increases are allowed if such increases are caused by routine maintenance, repair, and replacement. Emission increases are also allowed if caused by increases in production rate which can be accomplished without major capital expenditure. Increases in emissions caused by longer operating hours are also exempted from the rule on no emission increase. Another exemption is for the use of an alternative fuel or raw material if--prior to the date any standard becomes applicable--the existing facility was designed to accommodate that alternative use. Conversion to coal as stipulated in Section 111(a)(8) of the Clean Air Amendments of 1977 is not considered a modification. Emission increases caused by the addition or use of any system whose primary function is the reduction of air pollutants, are also exempt from the no emission increase rule.

5.2.2 Modified Pulverized Coal-Fired Steam Generators

For the purposes of determining if modification regulations apply or should apply, the pulverized coal-fired steam generator system is defined as including the following major components.

a) pulverizer system
b) combustion air system
c) steam generation system
d) draft system
e) fuel combustion system

The major points which define the inlets to the affected facility are:

1. The inlet to the pumps which feed water at steam generator pressure.
2. The inlet to the bins which directly feed the pulverized or stoker systems unless the bins are sized to store more than enoug coal to operate the steam generator 72 hours at full load. When large bins are installed, the inlet to the affected facility is t outlet of the bins feeding the pulverizer or stoker systems.
3. The combustion air intakes.

The major points which define the outlets of the affected facility ar

1. Any steam outlet
2. Any bottom ash outlet
3. The outlet of the last system installed before the stack, such as the outlet of any induced draft fan.

All components of the steam generator installed between these points are part of the affected facility except any air pollution control systems, suc as electrostatic precipitators, mechanical collectors, baghouses, or scrubbers.

Replacement of the pulverizer system with a similar system or replacement of component parts of the pulverizer system with similar parts would not be considered a modified source. However, replacement or redesign of the pulverizer system which would substantially change the physical characteristics of the pulverized coal may be a change where modification regulations apply.

Likewise changes in the design of the combustion air system which change the way combustion air is introduced to the combustion chamber would cause a source to be evaluated to determine if modification regulations should apply. Changing the combustion air damper settings is not a modification as long as no redesign of the combustion air system is involved.

The steam generation system includes the feedwater treatment system, watertubes, economizer, and superheat and reheat sections. Maintenance of these components is not a modification. Major redesign of these parts would cause a source to be evaluated to determine if modification regulations should apply. It is doubtful that redesign of the feedwater treatment system, the economizer, or the superheat or reheat sections would affect NO_x emissions. Redesign of the steam generation system components which affect combustion temperatures—such as the waterwall sections—could change NO_x emission characteristics.

Redesign of the draft system such as changing from induced draft conditions to pressurized firing conditions would cause a source to be evaluated to determine if modification regulations should apply.

Changes in the fuel combustion system which would be modifications are:

a) changes in the number of burners

b) changes in the type of burners

and c) changes in the location of burners.

Although a change to a different nitrogen content or a different moisture content coal or a switch from lignite to non-lignite coal might be considered a modification, these changes are exempted from modification evaluation by current regulations.[1]

Sources, which by reason of the date of new construction, are subject to the NO_x new source performance standard for coal combustion continue to be subject to the original standard in spite of any subsequent changes in solid fossil fuels or alteration. In cases where the original NO_x standard is revised to become more restrictive, none of the foregoing discussed modifications should cause the source regulated by the original NO_x standard to become subject to the more restrictive standard unless the modifications are so extensive as to be classed as reconstruction. (See Section 5.3).

5.2.3 <u>Modification of Oil- or Gas-Fired Steam Generators to Fire Coal</u>

The discussion of Section 5.2.3 is limited to modifications which would cause a source to become subject to NO_x new source performance standard modification regulations for large pulverized coal (other than lignite)-fired steam generators.

Alterations which might cause an existing oil or gas-fired steam generator to become subject to NO_x modification regulations for coal-fired steam generators are alterations involving a switch from gas or oil to coal. Current regulations provide that if the oil or gas-fired source is already designed to fire coal, a switch to coal does not cause the source to become subject to coal-fired steam generator NO_x modification regulations. In addition, Section 111(a)(8) of the Clean Air Amendments of 1977 exempts from the modification provisions of the

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

NOV 25 1986

MEMORANDUM

SUBJECT: Interpretation of Reconstruction (40 CFR 60.15)

FROM: John B. Rasnic, Acting Director John B Rasnic
Stationary Source Compliance Division
Office of Air Quality Planning and Standards

TO: James T. Wilburn, Chief
Air Compliance Branch

This is in response to your September 12, 1986 memorandum requesting the Stationary Source Compliance Division's (SSCD's) opinion of the Florida Electric Power Coordinating Group's (FCG's) interpretation of the reconstruction regulation at 40 CFR 60.15. FCG is proposing specific guidance on the items to be included in the fixed capital cost of fossil-fuel-fired steam electric plants.

Section 60.15 of the New Source Performance Standards (NSPS) specifies that reconstruction occurs if the fixed capital cost of the new components exceeds 50% of the fixed capital cost of a comparable entirely new facility, and if it is technologically and economically feasible for the facility to comply with the applicable NSPS. As cited in FCG's summary, the December 16, 1975 preamble to the reconstruction regulations defines fixed capital cost as the capital needed to provide all the depreciable components, including the costs of engineering, purchase and installation of major process equipment, contractor fees, instrumentation, auxiliary facilities, buildings and structures. Costs associated with the purchase and installation of air pollution control equipment are only included in the fixed capital cost to the extent that the equipment is required as part of the manufacturing/operating process. When determining reconstruction costs, care should be exercised to include only those costs associated with the reconstructed affected facility.

In making the final determination of whether the change in question constitutes reconstruction, the Administrator will consider all technical and economic limitations the facility may have in complying with NSPS. Points to be considered by the Administrator are listed at §60.15(f).

FCG has proposed a list of specific items to be included in the reconstruction costs for fossil-fuel-fired steam electric generating units. The list is composed of the accounting categories provided in the Federal Energy Regulatory Commission 18 CFR Part 101. SSCD and the Emission Standards and Engineering Division have reviewed this list and have determined that a substantial number of the items are not appropriate for inclusion in the cost analysis. Only the costs of items included in, and activities associated with, the affected facility are to be included in the reconstruction costs. The affected facility for fossil-fuel-fired steam electric plants consists only of the steam generating unit as defined at 40 CFR 60.40a and §60.41a. The affected facility is more specifically described at §60.41a in the proposed standards (Attachment A), and in the July 1978 Background Information Document (Attachment B).

Section 60.41a(a) of the proposed standards for electric utility steam generating units elaborates on the definition of steam generating unit: "... A steam generating unit includes the following systems: (1) Fuel combustion system (including bunker, coal pulverizer, crusher, stoker, and fuel burners, as applicable). (2) Combustion air system. (3) Steam generating system (firebox, boiler tubes, etc.). (4) Draft system (excluding the stack)." The affected facility then starts at the coal bunkers, and ends at the stack breeching.

The units which constitute the affected facility may best be conveyed by the diagram in Attachment C. As the diagram indicates, the following items are included in the affected facility: boilers and equipment, breeching, draft equipment, lighting systems, oil-burning equipment, pulverized fuel equipment, stoker or equivalent feeding equipment, and pressure oil systems. The following equipment would only be included in reconstruction costs to the extent that they directly service the boiler: foundations and structural steel, buildings, ash handling equipment (generally only the discharge valves to the ash hopper), boiler feed water system, coal handling and storage equipment (only the coal bunker and pulverizer), instruments and devices, ventilating equipment, wood fuel equipment (wood chipper), circulating pumps (just at the boiler), cooling system, fire extinguishing systems, mechanical meters, platforms, railings, steps, gratings, and steelwork. Likewise, engineering, purchase cost, installation, and contractor fees should be included only to the extent that they are associated with reconstruction of affected process equipment (the steam generating unit).

Many of the items included in FCG's proposed list are not part of the affected facility and should not, therefore, be included in reconstruction costs. These items are as follows: land, site preparation, demolition, boiler plant cranes, stacks, station piping, water purification equipment, water-supply systems, air cleaning and cooling apparatus, condensors, generator hydrogen, cranes and hoists, excitation systems identified with the main generating units, foundations and settings for turbogenerator, governors, lubricating systems, main exhaust and main steam piping, throttle and inlet valve, intake and discharge tunnels, turbogenerators, water screens, motors, and moisture separator for turbine steam. Auxiliary boilers should also be excluded from reconstruction cost calculations. SSCD agrees with the Florida Department of Environmental Regulation (DER) that the costs of land and site preparation should not be included in reconstruction costs. Land, site preparation, and demolition are not depreciable components as defined by fixed capital cost. Also, land, unlike process equipment, is not a component of the affected facility that need be or could be replaced.

In conveying our response to the Florida DER, please emphasize that although our evaluation is based on very general information, we recommend determination of reconstruction costs on a case-by-case basis, rather than on the generic basis proposed. If you have any questions, please contact Sally M. Farrell at FTS 382-2875.

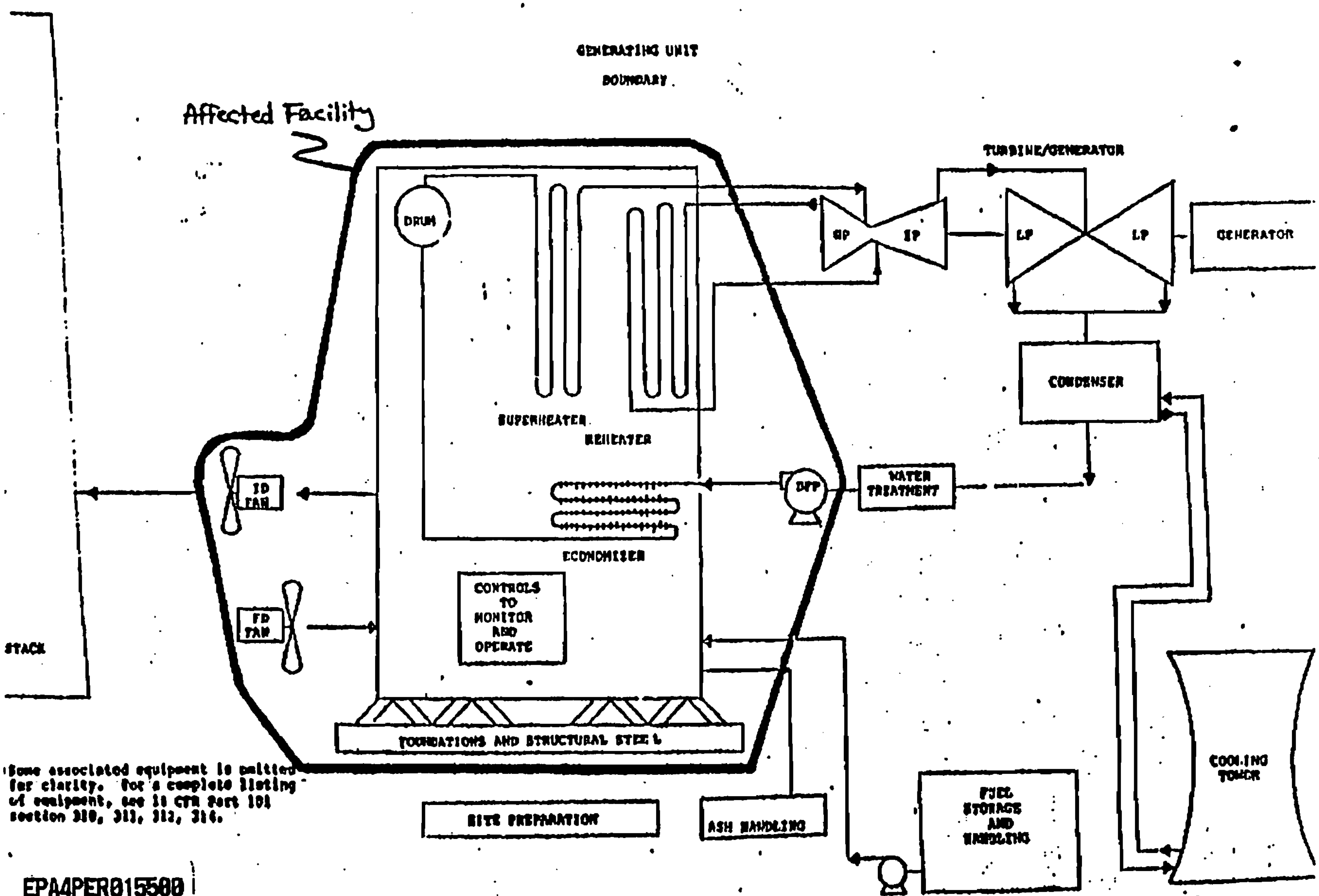
Attachments

cc: Jim Manning
Walt Stevensen

Attachment C

BEST AVAILABLE COPY

Modified FRC Diagram Showing Affected Facility for Fossil Fuel Steam Electric Plants



*Some associated equipment is omitted for clarity. For a complete listing of equipment, see 18 CFR Part 101 section 310, 311, 312, 314.

EPA4PER015580

Attachment I
August 24, 1999 Memorandum – Neeley to Cain

Determination Detail

Control Number: 0000102

Category: NSPS
EPA Office: Region 4
Date: 08/24/1999
Title: NSPS Subpart Dc Applicability
Recipient: Jerry Cain
Author: R. Douglas Neeley
Comments:

Subparts: Part 60, Dc — Small Indust.-Comm.-Inst. Steam Gen. Units

References: 60.15
60.15(b)
60.41c

Abstract:

Q: Will a new wood burner, propane burner, and heat exchanger being added to a thermal oil energy system be subject to NSPS Subpart Dc?

A: Yes. This equipment will constitute a new affected facility subject to Subpart Dc. Calculations presented by the company in this case in order to demonstrate that the addition of these components will not constitute reconstruction are not relevant because the new facility comprises new equipment that will supplement rather than replace the existing steam generating unit at the plant in question.

Letter:

4APT-ARB

Mr. Jerry W. Cain, P.E., D.E.E.
Chief
Environmental Permits Division
Air Division
Office of Pollution Control
Mississippi Department of Environmental Quality
P.O. Box 10385
Jackson, Mississippi 39289-0385

SUBJ: New Source Performance Standard Applicability to Equipment in a Thermal Oil Energy System at the Georgia Pacific Grenada Oriented Strand Board Plant, Duck Hill, Mississippi

Dear Mr. Cain:

Thank you for your letter of July 19, 1999, which requested a New Source Performance Standard (NSPS) applicability determination regarding changes that are being made to a thermal oil energy system at the referenced plant. This system combusts wood and propane in order to heat a thermal oil that is used to supply heat for equipment in Georgia Pacific's (GP's) oriented strand board (OSB) production line. Based upon our review of the information provided with your request, we have determined that a new wood fired burner, a new propane burner, and a heat exchanger being added to the plant will be subject to 40 C.F.R. Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

Subpart Dc is applicable to steam generating units with a heat input capacity of between 10 million British thermal units per hour (BTU/hr) and 100 million BTU/hr, and 40 C.F.R. Sec. 60.41c defines a steam generating unit as ". . . a device that combusts any fuel and produces steam or heats water or any other heat transfer medium." The current thermal oil energy system at GP has one wood burner and one propane burner, and the project described in your letter involves the addition of a new wood burner and a new propane burner. The existing wood burner at the plant will be dismantled and the existing propane burner will be retained as a back- up unit. Since the new burners and the associated heat exchanger being added to the thermal oil energy system at GP will combust fuel (wood and propane) in order to heat thermal oil which is a heat transfer medium, they constitute a steam generating unit as defined in Subpart Dc. In addition, the heat input capacities of the wood and propane burners (40 million BTU/hr and 42 million BTU/hr, respectively) are in the range that would make them subject to Subpart Dc if the unit is constructed, reconstructed, or modified after June 9, 1989.

In correspondence to your agency, GP presented calculations in an effort to demonstrate that adding the new burners and a new heat exchanger to its Grenada facility would not constitute reconstruction that would result in applicability under Subpart Dc. Reconstruction is defined in 40 C.F.R. Sec. 60.15 (b) as the replacement of components in an existing facility to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and a facility that is reconstructed becomes subject to the NSPS covering the specific source category into which it falls. Based upon our review of the information included with your letter, we have determined that the reconstruction provisions promulgated at 40 C.F.R. Sec. 60.15 are not relevant to the installation of the new burners and heat exchanger since they constitute a new steam generating unit that is supplementing, rather than replacing the existing steam generating unit at GP. Therefore, the new steam generating unit comprised of a wood burner, a propane burner, and a heat exchanger at GP's Grenada OSB plant will be subject to Subpart Dc.

The basis for our conclusion that the reconstruction provisions in 40 C.F.R. Sec. 60.15 do not apply to the upcoming changes at the Grenada OSB plant is that the proposed project constitutes construction of a new affected facility, rather than the replacement of components in an existing facility. Based upon the definitions in Subpart Dc and the enclosed U.S. Environmental Protection Agency (EPA) determination dated February 13, 1987, the existing wood burner, propane burner, heat exchanger, and certain ancillary equipment would constitute a steam generating unit since they are capable of combusting fuel to heat the oil in the thermal oil energy system. The two new burners and associated heat exchanger, along with the existing ancillary equipment shared with the existing burners and heat exchanger, will constitute a separate steam generating unit since they will be capable of independently combusting fuel to heat the oil in the thermal oil energy system. Since GP will have two separate steam generating units in place at the completion of its construction project, the new unit is not replacing the existing unit. Therefore, the reconstruction provisions in 40 C.F.R. Sec. 60.15 are not applicable to the project, and the newer of the two generating units will be subject to Subpart Dc.

If the construction project at GP had involved the replacement of both of the existing burners so that the company had only one operational steam generating unit at the completion of the project, it would be appropriate to evaluate the project in terms of reconstruction. If GP were to modify its construction plans in such a way that the reconstruction provisions in NSPS did apply, the calculations in the July 12, 1999, GP letter (enclosed with your July 19th letter) contain a major flaw that would have to be corrected in order to determine whether completely replacing the existing burners in the existing steam generating unit at the Grenada OSB plant would constitute reconstruction. Although the information submitted by GP did not contain enough information to enable us to revise the company's calculations in order to determine whether completely replacing the existing burners would constitute reconstruction, a cursory review of the submittal leads us to the conclusion that there is a high probability that the cost of the new burners, new heat exchanger, and other new equipment would exceed 50 percent of the cost for a comparable new steam generating unit.

The flaw in the reconstruction calculations in the July 12, 1999, letter from GP is that many of the components the company considered to be part of the steam generating unit actually fall outside the scope of the affected facility regulated under Subpart Dc. Including these additional components as part of the affected facility can result in erroneous conclusions when determining whether reconstruction has occurred since these additional components boost the apparent cost of a comparable new facility, and this increase in the total value of the facility makes it less likely that the value of the components being replaced will exceed 50 percent of the total facility cost. Based upon the definition of a steam generating unit in Subpart Dc, the primary components of the affected facility would be the equipment needed to combust fuel (i.e., burners and combustion chamber), the heat exchanger, and the combustion air supply system. In addition, based upon the enclosed February 13, 1987, EPA determination for a coal-fired boiler, the pumps returning the thermal oil to the heat exchanger would also be part of the affected facility. In its calculations, GP incorrectly classified a number of other components as part of the steam generating unit, and among these components were the following:

1. Thermal oil storage tanks are not part of the affected facility. The thermal oil in the steam generating unit at GP is analogous to the boiler feed water in a unit that generates steam to produce electricity, and according to EPA's February 13, 1987, determination regarding coal-fired boilers, the affected facility begins at the pump inlet on the boiler feed water system. Therefore, the steam generating unit at GP begins at the inlet to the pump supplying thermal oil to the heat exchanger section of the unit, and equipment such as thermal oil storage tanks upstream of this point are not part of the affected facility.

2. Pumps and piping used to distribute thermal oil to the OSB manufacturing line are not part of a steam generating unit. The basis for this conclusion is that pumps and piping used to distribute the thermal oil to the OSB manufacturing process are not used for combusting fuel or transferring heat to the thermal oil, and therefore, are not part of the affected facility defined in 40 C.F.R. Sec. 60.41c. According to EPA'S February 13, 1987, determination, the affected facility for a coal-fired boiler begins at the feed water pump inlet and ends at the boiler's steam outlet. Since the thermal oil in GP's boiler is analogous to the boiler feed water in a coal-fired unit, pumps and piping upstream of the last pump at the boiler inlet and downstream of the hot oil exit are not parts of the affected facility. Therefore, the cost of such pumps and piping cannot be included in the cost of a comparable new facility when determining whether reconstruction has occurred.

3. To the extent that it services the items listed above, a significant portion of the ancillary equipment (fittings, pipe racks, insulation, electrical equipment, etc.) that GP classified as part of the steam generating unit must also be excluded from the affected facility when determining whether reconstruction had occurred.

In its reconstruction calculations, GP provided cost estimates for both the existing and new sections of the thermal oil energy system, and revising these calculations to exclude equipment that is not part of the affected facility regulated under Subpart Dc would involve subtracting part of the cost both for the existing and new sections of the unit. Since the submittal does not contain the information that would be needed in order to apportion the cost for items that have components both inside and outside the affected facility, there is no practical way for us to do this with the data supplied by GP. Examples of such items would be fittings, insulation, and electrical components. Although we could not use the data supplied by GP to determine whether completely replacing the exiting burners in the thermal oil energy system would constitute reconstruction, we can assist you with the review of any revised calculations submitted by the company in the future. Based upon a limited review of the data supplied by GP thus far, however, it appears that the existing section of the thermal oil energy system contains a significantly greater proportion of components that are outside the affected facility regulated under Subpart Dc than does the new section of the unit. If this conclusion is true, the cost of the new components added to the facility will exceed 44 percent of the cost of a comparable entirely new facility (i.e., the proportion calculated by GP) and would be likely to exceed the threshold of 50 percent that would constitute reconstruction. For these reasons, we believe that the new burners to be installed at GP would be subject to Subpart Dc due to reconstruction even if both of the existing burners were replaced as part of the upcoming construction project.

If you have any questions about the determination provided in this letter, please contact Mr. David McNeal of the EPA Region 4 staff at (404) 562-9102.

Sincerely,

R. Douglas Neeley
Chief
Air and Radiation Technology Branch Air, Pesticides and Toxics Management Division

Enclosure

(1) February 13, 1987, EPA determination regarding the reconstruction of a coal-fired electric utility boiler

cc: Celina Sumrall, MS OPC

Dan Chadwick
564 - 7054

Attachment J

November 30, 2000 Letter – Katz to Daniel

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

November 30, 2000

Mr. John M. Daniel, Jr. PE., D.E.E.
Director, Air Program Coordination
Commonwealth of Virginia
Department of Environmental Quality
P.O. Box 10009
Richmond, Virginia 23240

Dear Mr. Daniel:

I am writing in response to your June 22, 2000 letter, regarding Prevention of Significant Deterioration (PSD)/Best Available Control Technology (BACT) questions you raised associated with a proposed modification at E.I. Du Pont De Nemours and Company's Spruance Plant (DuPont). In your letter, you indicated that the DuPont-Spruance Plant is a synthetic fiber manufacturing facility in Richmond, Virginia, and that the facility operates several solvent-spun synthetic fiber manufacturing lines, each making a different fiber type. The particular line in question is the facility's NOMEX line. Volatile organic Compound (VOC) emissions from the NOMEX line have averaged 400 tons/yr over the 1998-1999 time period, making it an existing major source under the New Source Review/Prevention of Significant Deterioration (NSR/PSD) regulations. You further indicate that the facility has not previously been permitted under PSD, and that the proposed modification at the facility will involve physically modifying the spinning and solvent recovery operations. There are no other emission units at the facility being physically modified as part of this proposed project. Based on this scenario, you have posed several questions regarding how to perform the NSR/PSD applicability determination and, if subject to PSD, where Best Available Control Technology (BACT) applies. Discussed below are the specific questions you've raised in your letter and our response.

The first question posed asked whether Dupont's proposed project should be considered a modification to one emission unit, with the emission unit being defined to include the spinning, wash/draw, and solvent recovery operations together. These operations together constitute the solvent-spun synthetic fiber process. It was indicated in your letter that this definition of emission unit could be supported by the definition of affected facility contained in the New Source Performance Standard (NSPS) for this source category (Subpart HHH) which defines the entire solvent-spun synthetic fiber process as the affected emission unit. Or, alternatively, you asked whether the correct approach would be to consider each part of the process (ie., spinning, solvent recovery, wash/draw) as an individual emission unit. It was indicated in your letter, this approach might be more consistent with how emission unit have been historically defined under PSD regulations, both state-wide (Virginia) and nationally. You then wanted to know how our response to this question would affect the PSD applicability calculation and BACT requirement.

In order to fully address these questions, I would first like to discuss the steps in the process to determine PSD applicability.

A modification is subject to PSD review only if (1) the existing source that is being modified is "major", and (2) the net emissions increase of any pollutant emitted by the source, as a result of the modification, is "significant". In this case, the existing source is major. In order to determine the net emissions increase of any pollutant emitted by the source as a result of the modification, you need to first determine whether the proposed emissions increases at the major source are by itself significant (significant emission rates are defined in 40 CFR §52.21). This is the first step in determining whether a "net emissions increase" has occurred (see definition of net emissions increase, 40 CFR §52.21). Specifically, you would include any increase in actual emissions from a particular physical change or change in the method of operation at a stationary source. This would include emissions increases from the new and modified emissions units and any other plant-wide emissions increases (e.g., debottlenecking increases). Therefore, whether you define the entire process as the emission unit or each part of the process as an individual emission unit, it would not change the PSD applicability calculation since all emissions increases associated with a modification must be included in the calculations.

In order to determine how the "emissions unit" should be defined in this case, EPA would first look to the definition of "emissions unit" found at 40 CFR 51.165(a)(1)(vii). Here it defines "emissions unit" as "any part of a stationary source which emits or has the potential to emit any pollutant subject to regulation under the Act". Furthermore, the federal regulations define "potential to emit" as "the maximum capacity of a stationary source to emit a pollutant under its physical and operational design". For the purpose of defining an emission unit, air pollution control equipment can be considered as part of the operational design of the unit. Therefore, in defining what constitutes an emissions unit, EPA considers appropriate application of control technology to be an important criterion.

In order to evaluate appropriate application of control technology once PSD is triggered, we look to the definition of BACT which states:

> "Best available control technology means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the reviewing authority, 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 combination techniques for control of such pollutant.....".

During each BACT analysis, which is done on a case-by-case basis, the reviewing authority evaluates the energy, environmental, economic and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring. In order to determine how to evaluate emissions control at a modified source, all available information should be used. An NSPS is one source of information that may be helpful in defining an emission unit for the purpose of evaluating control options. In this case, NSPS, Subpart HHH - Standards of Performance for Synthetic Fiber Production Facilities, provides relevant information on how control of emissions from modification to the spinning and solvent recovery processes should be evaluated.

NSPS, Subpart HHH is applicable to each solvent-spun synthetic fiber process, commencing construction or reconstruction after November 23, 1982, that produces more than 500 megagrams of fiber per year. Although Dupont's NOMEX line was originally constructed in the 1970's, and is currently not subject to this NSPS, the rationale contained in the NSPS for determining emissions control from this type of line is still relevant in a BACT analysis. The NSPS defines the solvent-spun synthetic fiber process as the total of all equipment having a common spinning solution preparation system or a common solvent recovery system, and that is used in the manufacture of solvent-spun synthetic fiber. It includes spinning solution preparation, spinning, fiber processing (wash/draw) and solvent recovery, but does not include the polymer production equipment. The November 23, 1982 preamble to NSPS Subpart HHH provides the rationale for designating the solution preparation area or solvent recovery system as the affected facility. It states that "...designating each group of lines with a common solution preparation area or solvent recovery system as an affected facility represents the smallest unit from which emissions can be determined reasonably from both a technical and cost standpoint...". In promulgating this NSPS, it was determined that the "affected facility" could be controlled in a technically-achievable and cost-effective manner, and we have no present reason to question that assessment. Therefore, we think it is appropriate to follow the NSPS in this case.

Given this rationale, it is EPA's position that the modified emissions unit, in this case, consists of the entire solvent-spun synthetic fiber process, which would include all equipment within the solution preparation area and solvent recovery system. Although an emissions unit may consist of a single piece of equipment, here the appropriateness of applying controls over multiple units justifies viewing the affected facility as defined by NSPS Subpart HHH, to be the emissions unit. Accordingly, EPA would require a BACT analysis to be conducted for the entire process when there is a modification to any equipment within the solution preparation area or solvent recovery system in order to appropriately evaluate control options. This would mean that modifications to the spinning operation and/or solvent recovery system, resulting in the triggering of PSD, would constitute a modification to the entire emissions unit, which includes the wash/draw operation, and the BACT analysis should include all these operations.

This determination is consistent with guidance issued by EPA, Region VIII in a letter dated February 6, 1990, regarding a determination of Lowest Achievable Emission Rate (LAER) for Coors Container. In this letter, EPA determined that an emissions unit consisted of the entire coating operation (topcoat, basecoat, etc) based on the NSPS definition of affected facility for that source category (Subpart WW). The NSPS definition of emissions unit was relied on because the rule provided a rationale as to why these processes should be grouped together for purposes of setting a unique emission limitation covering all the equipment. It was determined that this was the most technically-achievable and cost-effective way to evaluate control for these operations. Therefore, in this case, EPA indicated that a BACT or LAER analysis should be done for each coating operation.

Our position on this particular matter is only provided as guidance, as it remains the Commonwealth's particular responsibility to make the final determination under your federally approved New Source Review regulations. I hope we have fully addressed your questions. If you would like to discuss these issues further, please contact me at (215) 814-2654, or Donna Weiss of my staff at (215) 814-2198.

Sincerely,

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Judith M. Katz, Director
Air Protection Division