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40 CFR Parts 51 and 52

Prevention of Significant Deterioration (PSD) and Non-Attainment New Source Review (NSR): Equipment Replacement Provision of the Routine Maintenance, Repair and Replacement Exclusion; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[FRL–7575–9; RIN 2060–AK28; Electronic Docket OAR–2002–0068; Legacy Docket A–2002–04]

Prevention of Significant Deterioration (PSD) and Non-Attainment New Source Review (NSR): Equipment Replacement Provision of the Routine Maintenance, Repair and Replacement Exclusion

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The EPA is finalizing revisions to the regulations governing the NSR programs mandated by parts C and D of title I of the Clean Air Act (CAA). Today's changes reflect EPA's incorporation of comments from the proposed rule for ''Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NSR): Routine Maintenance, Repair and Replacement.'' These changes provide a category of equipment replacement activities that are not subject to Major NSR requirements under the routine maintenance, repair and replacement (RMRR) exclusion. The changes are intended to provide greater regulatory certainty without sacrificing the current level of environmental protection and benefit derived from the NSR program. We believe that these changes will facilitate the safe, efficient, and reliable operation of affected facilities.

EFFECTIVE DATE: This final rule is effective on December 26, 2003.

ADDRESSES: *Docket.* Docket No. A–2002–04 (Electronic docket OAR–2002–0068), containing supporting information used to develop the proposed rule and today's final rule, is available for public inspection and copying between 8:00 a.m. and 4:30 p.m., Monday through Friday (except government holidays) at the Air and Radiation Docket and Information Center (6102T), Room B–108, EPA West Building, 1301 Constitution Avenue, NW, Washington, D.C. 20460; telephone (202) 566–1742, fax (202) 566–1741. A reasonable fee may be charged for copying docket materials.

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of this final rule will also be available on the WWW through the Technology Transfer Network (TTN). Following signature, a copy of the rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules: *http://www.epa.gov/ttn/oarpg.*

FOR FURTHER INFORMATION CONTACT: Mr. Dave Svendsgaard, Information Transfer and Program Integration Division (C339–03), U.S. EPA Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711, telephone 919–541–2380, or electronic mail at *svendsgaard.dave@epa.gov*, for questions on this rule.

SUPPLEMENTARY INFORMATION:

Regulated Entities

Entities potentially affected by this final action include sources in all industry groups. The majority of sources potentially affected are expected to be in the following groups:

Industry group	SIC [a]	NAICS [b]
Electric Services	491	221111, 221112, 221113, 221119, 221121, 221122
Petroleum Refining	291	324110
Industrial Inorganic Chemicals	281	325181, 325120, 325131, 325182, 211112, 325998, 331311, 325188
Industrial Organic Chemicals	286	325110, 325132, 325192, 325188, 325193, 325120, 325199
Miscellaneous Chemical Products	289	325520, 325920, 325910, 325182, 325510
Natural Gas Liquids	132	211112
Natural Gas Transport	492	486210, 221210
Pulp and Paper Mills	261	322110, 322121, 322122, 322130
Paper Mills	262	322121, 322122
Automobile Manufacturing	371	336111, 336112, 336211, 336992, 336322, 336312, 336330, 336340, 336350, 336399, 336212, 336213
Pharmaceuticals	283	325411, 325412, 325413, 325414

[a] Standard Industrial Classification.
[b] North American Industry Classification System.

Entities potentially affected by this final action also include State, local, and tribal governments that are delegated authority to implement these regulations.

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I. General Information

A. How Can I Get Copies of This Document and Other Related Information?

1. *Docket.* The EPA has established an official public docket for this action under Docket ID No. A–2002–04. The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Although a part of the official docket, the public docket does not include Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. The official public docket is the collection of materials that is available for public viewing at the EPA Docket Center, (Air Docket), U.S. Environmental Protection Agency, 1301 Constitution Ave., NW., Room: B108, Mail Code: 6102T, Washington, DC, 20004. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is (202) 566–1742. A reasonable fee may be charged for copying.

2. *Electronic Access.* You may access this **Federal Register** document electronically through the EPA Internet under the ''**Federal Register**'' listings at *http://www.epa.gov/fedrgstr/.*

An electronic version of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. You may use EPA Dockets at *http://www.epa.gov/edocket/* to submit or view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. Once in the system, select ''search,'' then key in the appropriate docket identification number.

Certain types of information will not be placed in the EPA Dockets. Information claimed as CBI and other information whose disclosure is restricted by statute, which is not included in the official public docket, will not be available for public viewing in EPA's electronic public docket. EPA's policy is that copyrighted material will not be placed in EPA's electronic public docket but will be available only in printed, paper form in the official public docket. To the extent feasible, publicly available docket materials will be made available in EPA's electronic public docket. When a document is selected from the index list in EPA Dockets, the system will identify whether the document is available for viewing in EPA's electronic public docket. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the docket facility identified in section I.A.1. of this preamble. The EPA intends to work towards providing electronic access to all of the publicly available docket materials through EPA's electronic public docket.

For additional information about EPA's electronic public docket visit EPA Dockets online or see 67 FR 38102, May 31, 2002.

B. Where Can I Obtain Additional Information?

In addition to being available in the docket, an electronic copy of today's final rule is also available on the WWW through the Technology Transfer Network (TTN). Following signature by the EPA Administrator, a copy of this rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at *http://www.epa.gov/ttn/oarpg.* The TTN provides information and technology exchange in various areas of air pollution control. If more information regarding the TTN is needed, call the TTN HELP line at (919) 541–5384.

II. Background

A. What Is the RMRR Exclusion?

Title I of the Clean Air Act (CAA) established the New Source Review program [1] to help control airborne emissions from major new stationary sources of pollution. Under the program, anyone who seeks to construct a new stationary source that will be a major source of regulated pollutants must obtain a permit from State authorities (or, where a State has not established its own program, from EPA directly) before beginning construction of the source. In order to obtain the permit, the owner or operator must, among other things, demonstrate that the new source will have state-of-the-art pollution control devices.

The NSR program does not generally affect existing sources, but it does apply if they undergo a ''modification.'' The NSR provisions of the CAA do not create their own definition of ''modification,'' instead borrowing the definition of the term established by section 111 of the CAA, which defined the term for purposes of the New Source Performance Standards (NSPS) program. That definition states that ''[t]he term ''modification'' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' Under 40 CFR parts 51 and 52, the rules we have promulgated to carry out the NSR program, ''major modification'' is similarly defined as any physical change in or change in the method of operation of a major stationary source that would result in: (1) A significant emissions increase of a regulated NSR pollutant; and (2) a significant net emissions increase of that pollutant from the major stationary source.[2] The regulations further provide that certain activities do not constitute a ''physical change or change in the method of operation'' under the definition of ''major modification.'' One category of such activities is routine maintenance, repair and replacement (RMRR). The regulatory provisions excluding RMRR from the definition of change constitute the RMRR exclusion.

B. Issues Surrounding the RMRR Exclusion

Until today, the NSR regulations have not further specified what types of activities are encompassed by the term RMRR. Heretofore, we have applied the RMRR exclusion exclusively on a case-by-case basis using a multi-factor test for determining whether a particular activity falls within or outside the exclusion. We have made these case-by-case determinations both in the context of applicability determinations, where a source or permitting authority has requested EPA's guidance concerning whether a particular activity falls within the exclusion or requires a permit, and

[1] We broadly use the term ''New Source Review,'' or NSR, to encompass both the PSD and the Non-attainment New Source Review program.

[2] Once a modification is determined to be major, NSR requirements apply only to those specific pollutants for which there would be a significant net emissions increase.

in the context of enforcement actions, where we have challenged an activity undertaken by a source after the fact and the source has asserted that the activity was permissible under the exclusion.

This case-by-case approach has been praised for its flexibility, but criticized for hampering activities important to assuring the safe, reliable and efficient operation of existing plants. Specifically, some of the case-by-case determinations we have made, particularly over the past decade, and particularly in a series of enforcement actions, have been criticized for giving the exclusion a narrow scope that disallows replacement of significant plant components with identical or functionally equivalent components. Critics argue that the effect is to discourage plant owners or operators from engaging in replacements that are important to restoring, maintaining and improving plant safety, reliability, and efficiency. They further argue that this effect is exacerbated by what they assert are the uncertainties inherent in the case-by-case approach.

To elaborate on the uncertainty issues: Unless an owner or operator seeks an applicability determination from his or her reviewing authority, it can be difficult for the owner or operator to know with reasonable certainty whether a particular activity constitutes RMRR. This gives the owner or operator five choices, two of which the owner or operator is not likely to select, and the other three of which have significant drawbacks for the productivity of the plant.

First, the owner or operator may simply seek an NSR permit. That course, however, is likely to be time-consuming and expensive, since it will likely result in a requirement to retrofit an existing plant with state-of-the-art pollution controls which often is very costly and can present significant technical challenges. Therefore, an owner or operator is not likely to select this option if it can be avoided.

Second, the owner or operator may proceed at risk without a reviewing authority determination. That option, however, is also not likely to be attractive where a significant replacement activity is involved, because if the owner or operator proceeds without a reviewing authority determination and if we later find that he or she made an incorrect determination on its own, the owner or operator faces potentially serious enforcement consequences. Those consequences could well include substantial fines (along with the further consequences of having been determined to be in violation of the CAA) and penalties and a requirement to install the state-of-the-art pollution controls, even though those controls present technical issues or represent a significant enough expenditure that they likely would have deterred the owner or operator from seeking a permit in the first place. The owner or operator is not likely to take this risk if he or she believes there is a high probability of these kinds of consequences and if he or she has other options.

Third, the owner or operator may seek an applicability determination. That process, too, is time-consuming and expensive, albeit typically less so than seeking a permit. This path presents a potentially significant barrier to today's global, quick-to-market industries, such as computer chips, pharmaceuticals, and autos. This approach also is likely to result in substantial foregone activities that would enhance the safety, reliability and efficiency of the plant while awaiting the applicability determination.

Fourth, the owner or operator may forego or curtail replacements that would enhance the safe, reliable, or efficient operation of its plant, instead opting to repair existing components even though they are inferior to current day replacements because they likely have deteriorated with use and probably are less advanced and less efficient than current technology. Foregoing the replacement activities altogether will reduce plant safety, reliability and efficiency; curtailing or postponing them does as well, differing only in the degree of these effects.

Finally, the owner or operator may curtail the plant's productive capacity by replacing components with less than the best technology in order to be more certain that the replacement is within the RMRR regulatory bounds, or he or she may agree to limit the source's hours of operation or capacity or install less than state-of-the-art air pollution controls to ensure no increase in emissions. Either of those courses, however, will also result in loss of plant productivity.

The uncertainties are also problematic for State and local reviewing authorities. They require those authorities to devote scarce resources to make complex determinations, including applicability determinations, and consult with other agencies to ensure that any determinations are consistent with determinations made for similar circumstances in other jurisdictions and/or that other reviewing authorities would concur with the conclusion.

Industry commenters strongly echoed these concerns, asserting that the expense and delay associated with NSR scrutiny, whether or not the activity is ultimately judged to be subject to major NSR, have caused a number of facilities to forego needed and beneficial maintenance, repair, and replacement activities, including ones that would likely have reduced emissions. In our June 2002 report to the President, we similarly concluded that the NSR program has impeded or resulted in the cancellation of projects that would have maintained and improved the reliability, efficiency, or safety of existing energy capacity.

We are persuaded that we should change the approach to the RMRR exclusion that we have been following for equipment replacements. The approach we have been taking often has not encompassed the replacement of existing components with identical or similar new components that serve the same function, that represent a small fraction of the value of the process unit of which they are a part, that do not change the process unit's basic design parameters, and that do not cause the process unit to exceed any emission limitations. For the reasons noted above, this approach tends to have the effect of leading sources to refrain from replacing components, to replace them with inferior components, or to artificially constrain production in other ways. We are persuaded that none of these outcomes advanced the central policy of the major NSR program as applied to existing sources, which is not to cut back on emissions from existing major stationary sources through limitations on their productive capacity, but rather to ensure that they will install state-of-the-art pollution controls at a juncture where it otherwise makes sense to do so. We also do not believe the outcomes produced by the approach we have been taking have significant environmental benefits compared with the approach we are adopting today and, indeed, we believe our new approach may well produce environmental improvements as compared to the old one.

We are also persuaded that uncertainties surrounding the scope of the exclusion that are associated with the case-by-case approach tend to exacerbate the problem outlined above. These uncertainties can discourage replacements that would promote safety, reliability and efficiency even in instances where, if the matter were brought to EPA, we would determine that the replacement in question was RMRR. Such discouragement results in lost capacity and lost opportunities to improve energy efficiency and reduce air pollution.

We believe that these problems will be significantly reduced by the rule we

are adopting today. This rule specifies that the replacement of components of a process unit with identical components or their functional equivalents will come within the scope of the exclusion, provided the cost of replacing the component falls below 20 percent of the replacement value of the process unit of which the component is a part, the replacement does not change the unit's basic design parameters, and the unit continues to meet enforceable emission and operational limitations.

Our new equipment replacement approach will allow owners or operators to replace components under a wider variety of circumstances than they have been able to do under our prior RMRR approach. It also provides more certainty both to source owners or operators who will be able better to plan activities at their facilities, and to reviewing authorities who will be able better to focus resources on other areas of their environmental programs rather than on time-consuming RMRR determinations. The effect should be to remove disincentives to undertaking RMRR activities falling within the rule, thereby enhancing key operational elements such as efficiency, safety, reliability, and environmental performance. For example, we anticipate that improved safety and reliability will result in more stable process operations and reduce periods of startup, shutdown, and malfunction and the increased emissions usually associated with them. Accordingly, we believe the rule will promote the central purpose of Title I of the CAA, ''to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population.'' CAA section 101.

We note that we continue to believe that our prior narrower and entirely case-by-case approach to the RMRR exclusion was consistent with the relevant language of the CAA and a reasonable effort to effectuate its policies. At the same time, we also believe that the final rule's categorical exclusion of certain replacement activities and the broader definition of RMRR on which that exclusion is premised are likewise consistent with the statute's language and represent a better accommodation of the statute's twofold ends. We therefore have decided to adopt the final rule.

C. Process Used To Develop This Rule

In the 1992 ''WEPCO Rule'' preamble, we declared our intent to issue guidance on the subject of RMRR. In 1994, as an outgrowth of meetings with the Clean Air Act Advisory Committee, we developed, for discussion purposes only, a preliminary draft that presented possible ways of how RMRR could be defined. We received a substantial volume of comments on this document. We subsequently decided not to include this preliminary draft approach in our 1996 NSR proposed rulemaking.

In 2001, the President's National Energy Policy directed EPA in consultation with the Department of Energy (DOE) and other Federal agencies to review the impact of NSR on investment in new utility and refinery generation capacity, energy efficiency and environmental protection. Our Report to the President illustrated the problems associated with our prior case-by-case approach to identifying RMRR activities and underscored the advantages of establishing an objective bright-line approach for administering the RMRR provision.

We held conference calls with various stakeholders during October 2001 (including representatives from industry, State and local governments, and environmental groups) to discuss new ideas that were raised as to how the RMRR provision might be improved. The proposed RMRR rule reflected many of the ideas discussed in those meetings. Today's final rule on the equipment replacement provision is based on careful consideration of comments received on the proposed RMRR rule (67 FR 80920, December 31, 2002), where we sought comment on all aspects of our proposed approaches. Today's rule represents final action on only one part of what we proposed in December 2002—the equipment replacement provision. We have decided, for now, not to take final action on the proposed annual maintenance, repair and replacement allowance approach.

D. What We Proposed

The RMRR proposal offered for comment two cost-based approaches for determining what constitutes routine maintenance, repair, and replacement. Under the proposal, facilities could have relied on a facility-wide annual maintenance, repair and replacement allowance and/or an equipment replacement cost threshold to determine whether major NSR requirements were triggered by performing plant maintenance, repair and replacement activities. The proposal additionally outlined two options based on the capacity and age of a facility. We solicited comment on all aspects of the proposed approaches as well as any other viable option for clarifying the term ''routine maintenance, repair, and replacement.'' We took public comment on the proposed rule until May 2, 2003—120 days following publication in the **Federal Register**.

Under the ''annual maintenance, repair and replacement allowance,'' an annual maintenance cost allowance would be established for each industrial facility based on an industry-specific percentage. For the percentage, we considered using the Internal Revenue Service ''Annual Asset Guideline Repair Allowance Percentages'' (AAGRAP), which for years has been used as an integral part of an exclusion under the New Source Performance Standard (NSPS) program. A multi-year allowance approach, in addition to the annual approach, was also offered for consideration in the proposal.

Safeguards were proposed to ensure that the types of activities undertaken under the annual allowance are not activities that should be subject to greater scrutiny. These safeguards include: (1) No new unit may be installed; (2) no unit may be replaced in its entirety; and (3) changes may not cause an increase in the short-term emission rate of any regulated NSR pollutant.

Under the ''equipment replacement provision,'' or ERP, we proposed to streamline the process for determining if major NSR permitting requirements apply to replacement of existing equipment with identical new equipment or with functionally equivalent equipment. Per-replacement-of-component(s) thresholds, potentially up to 50 percent of the cost of replacing the process unit, were suggested by the proposal. As long as the threshold was not exceeded and the basic design parameters remained unchanged, the activity would be considered RMRR under this approach.

Under the proposal, all activities that fell within the annual maintenance, repair and replacement allowance or the equipment replacement threshold and that met all the other criteria for these provisions would be considered RMRR without further review. Activities that were unable to be accommodated under the annual maintenance, repair and replacement allowance or the equipment replacement threshold could still qualify for the RMRR exclusion after a case-by-case review in accordance with current rules.

We solicited comments on all aspects of our RMRR proposal.

III. Equipment Replacement Provision

A. Overview and Justification for Today's Final Action

Today, we are revising certain provisions of the major NSR program by

finalizing the equipment replacement provision (ERP) to specify activities that will automatically qualify for the RMRR exclusion. This rule is effective on December 26, 2003. At this time, we are not taking action on our proposed annual maintenance, repair and replacement allowance approach.

Although many commenters requested that we further clarify the case-by-case approach for determining whether an activity is RMRR, we are not taking action on this suggestion at this time. We are still considering what, if any, changes should be made to that policy. In the meantime, the case-by-case approach will remain available for the owner or operator of a source to use as an alternative and/or supplement to today's ERP.

Under today's rule, an activity (or aggregations of activities) can qualify for the ERP if: (1) It involves replacement of any existing component(s) [3] of a process unit with component(s) that are identical or that serve the same purpose as the replaced component(s); (2) the fixed capital cost of the replaced component(s), plus costs of any activities that are part of the replacement activity (*e.g.*, labor, contract services, major equipment rental, and associated repair and maintenance activities),[4] does not exceed 20 percent of the current replacement value of the process unit; and (3) the replacement(s) does not alter the basic design parameters of the process unit or cause the process unit to exceed any emission limitation or operational limitation (that has the effect of constraining emissions) that applies to any component of the process unit and that is legally enforceable.

Today's final rule specifies the procedures by which the owner or operator of a source selects the basic design parameters for steam electric generating facilities and for other types of process units. Specifically, for steam electric generating facilities, we have clarified our proposed approach by specifying maximum hourly heat input and fuel consumption rate [5] as basic design parameters. We are also allowing owners or operators of steam electric generating facilities the option to select a pair of parameters based on the process unit's output—more specifically, maximum hourly electric output rate or maximum steam flow rate—as an alternative to the previously proposed input-based parameters. Likewise, we are retaining our proposed approach of specifying maximum rate of fuel or material input for other types of process units, but we also allow you to use maximum rate of heat input, or maximum rate of product output if you prefer an output-based basic design parameter. In addition, we allow you to propose an alternative basic design parameter(s), if the above options are inappropriate for your process unit.

We are not specifically defining the basis for determining the replacement value of a new process unit. Instead, the final rule provides you with the flexibility of using any of the following: (1) Replacement cost; [6] (2) invested cost, adjusted for inflation; (3) the insurance value, where the insurance value covers complete replacement of the process unit (rather than, for example, lost revenue replacement); or (4) another accounting procedure to establish a replacement value of the process unit if such accounting procedure is based on Generally Accepted Accounting Principles (GAAP). The GAAP are the conventions, rules and procedures that define accepted accounting practice for recording and reporting financial information, including broad guidelines as well as detailed procedures. The basic doctrine was set forth by the Accounting Principles Board of the American Institute of Certified Public Accountants, which was superseded in 1973 by the Financial Accounting Standards Board.

If you choose to use options 3 or 4 to determine the replacement value for a particular process unit, you must send a notice reflecting your decision to your reviewing authority. The first time that an owner or operator submits such a notice for a particular process unit, the notice may be submitted at any time, but any subsequent notice for that process unit may be submitted only at the beginning of the process unit's fiscal year. You must continue to use the same basis to evaluate any additional activities that you undertake on that process unit within that same fiscal year. If you have provided notice of using either option 3 or 4, then the reviewing authority will assume that the same method will be used for subsequent fiscal years unless you send a notice to them declaring your intent to use another method. In the absence of providing any notification to your reviewing authority, you must use option 1 or 2.

The final rules also set forth a definition of process unit, specifically delineate the boundary of the process unit for certain specified industries, and define a functionally equivalent replacement. A more detailed discussion of these requirements and our rationale for this action is contained in other parts of this preamble section.

Today's final rules are designed to allow you to engage in activities that facilitate the safe, reliable and efficient operation of your source. We believe that today's final action broadens the major NSR program exclusion for equipment replacements and provides you with additional certainty as to what equipment replacement activities qualify for the RMRR exclusion. By adding certainty to the process, we are removing the disincentives to undertaking routine equipment replacements and promoting proper operational planning to facilitate safe, reliable and efficient operations. When an activity qualifies for the ERP, it will be considered RMRR and excluded from major NSR without regard to other considerations. In many cases, we believe that maintaining safe, reliable and efficient operations will have the corresponding environmental benefit of reducing the amount of pollution generated per product produced. The final rules also will reduce the resource burden on reviewing authorities resulting from implementation of the existing, case-by-case process for determining RMRR. In these respects, the final rules are consistent with the central purpose of the CAA, ''to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population.'' CAA section 101.

B. What Is an Identical or Functionally Equivalent Replacement and Why Should Such an Activity Be Considered RMRR?

We proposed to exclude the replacement of existing equipment with identical or functionally equivalent components. As we observed at the time of our RMRR proposal, we believe that most identical and functionally equivalent replacements are necessary for the safe, efficient and reliable operations of virtually all industrial operations; are not of regulatory concern; will improve air quality (*e.g.*, by decreasing startup, shutdown, and malfunctions); and thus should qualify

[3] For the sake of clarity, we want to be clear that the term ''component'' is meant to be applied broadly and read broadly to include replacements of both large components, such as economizers, reheaters, etc. at a boiler, as well as small items, such as screws, washers, gaskets, *etc.*

[4] We note that certain ancillary costs incurred during a given replacement activity should not be part of the replacement activity, such as replacement power that must be purchased during the maintenance shutdown of an electric utility.

[5] Actually proposed as ''fuel consumption specifications.''

[6] Replacement cost can be either an estimate of the fixed capital cost of constructing a new process unit or the current appraised value of the process unit.

for the ERP under the RMRR exclusion. We believe industrial facilities are constructed with the understanding that certain equipment failures are common and ongoing maintenance programs that include replacing components in order to maintain, restore, or enhance the reliability, safety, and efficiency of a plant are routine. Conversely, delaying or foregoing maintenance could lead to failure of the production unit and may create or add to safety concerns.

When such equipment replacement occurs, the replaced component is inherent to both the design and purpose of the process unit, and there is no reason to believe that such activity will cause the unit to emit above its original design capacity. Moreover, most of these replacements are conducted at industrial facilities to maintain proper operations and to implement good engineering practices. For example, if a pump associated with a distillation column fails and is replaced with an identical new pump, we believe that such a common activity is and should be considered an excluded replacement. It is not a ''change'' to the plant, since it merely maintains the plant as designed. Instead, it is the type of activity expected to occur to maintain the plant. Therefore, we think replacements like this properly fall within the exclusion for ''routine maintenance, repair and replacement.'' We also believe treating them in this fashion is consistent with the basic policies of the CAA: that existing plants are subject to major NSR permitting requirements only when they engage in an activity that constitutes an opportune time to install state-of-the-art pollution control equipment.

We also believe that this principle extends beyond the replacement of equipment with identical equipment. When equipment is wearing out or breaks down, it often is replaced with equipment that serves the same purpose or function but is different in some respects or improved in some ways in comparison with the equipment that is removed. To continue with the example used above, if, instead of replacing the worn out distillation column pump with an identical one, the owner or operator replaced it with a new and improved model, it does not seem to us that this changes the fundamental reasons for treating that replacement as likewise within the scope of ''routine maintenance, repair and replacement.''

This is particularly true since technology is constantly changing and evolving. When equipment of this sort needs to be replaced, it often is simply not possible to find the old-style technology. Owners or operators may have no choice but to purchase and install equipment reflecting current design innovations. Even if it is possible to find old-style equipment, it seems unnecessary and undesirable to generally construe NSR permitting requirements in a manner that is bound to deter owners or operators from using the best equipment that suits the given need when replacements must be installed.

The limiting principle here is that the replacement equipment must be identical or functionally equivalent and must not change the basic design parameters of the affected process unit (*e.g.*, for electric utility steam generating units, this might mean heat input and fuel consumption specifications). We also believe, however, that we need not and should not treat efficiency as a basic design parameter as we do not believe NSR was intended to impede industry in making energy and process efficiency improvements. We believe such improvements, on balance, will be beneficial both economically and environmentally. This treatment of efficiency should address the concern and perception that the NSR program serves as a barrier to activities undertaken to facilitate, restore, or improve efficiency, reliability, availability, or safety of a facility.

Today's rule does not distinguish between the replacement of components that are expected to be replaced frequently or periodically and the replacement of components that may occur on a less frequent or one-time basis. It likewise does not distinguish between the replacement of larger and smaller components, instead requiring greater scrutiny if the replacement in question is part of an activity that exceeds 20 percent of the replacement value of the process unit.

Our decisions on these points are derived from reflection on the function of the exclusion in the context of the CAA. As explained above, and as described more fully in our legal analysis set forth below, we do not believe that application of the major NSR program to ''modified'' plants is designed to require existing plants that are continuing to operate in a manner consistent with their original design to curtail their rate of production or hours of operation beyond limitations set forth in their existing permits. We likewise do not believe that the program is designed to discourage plants from replacing parts or components so as to preserve their ability to produce at that rate. Rather, we believe Title I of the Clean Air largely leaves to State and local permitting authorities whether to require adjustments in the operations of those plants in order to reduce emissions to the degree needed to attain or maintain national air quality standards, and how to weigh the trade-offs such adjustments may produce in terms of potential economic impacts and loss of productivity. Instead, we believe the central function of the application of major NSR permitting requirements to ''modifications'' is to assure that plants install state-of-the-art pollution controls.

We recognize that on these points, the approach taken by our final rule thereby differs in some respects from the multi-factor, case-by-case approach we have been using in identifying RMRR, and particularly from some of our applications of that test to certain equipment replacements. We believe, however, that this adjustment in our approach is fully warranted for the reasons outlined above, and described more fully in our legal analysis below.

The following examples of functionally equivalent replacements under today's rule include:[7]

- Replacing worn out pipes in a chemical process plant with pipes that are constructed of different metallurgy (*e.g.*, to help reduce corrosion, erosion, or chemical compatibility problems).
- Replacing an analog controller with a digital controller, even though a similar analog controller can still be purchased and even though the new controller would allow for more precise control. A good example was presented to us by the forest products industry during our review of the NSR program's impacts on the energy sector. A company in that sector needed to replace outdated analog controllers at a series of six batch digesters. In this case, the original controllers were no longer manufactured. The new digital controllers, costing approximately $50,000, are capable of receiving inputs from the digester vessel temperature, pressure, and chemical/steam flow. The new controllers would have more precisely filled and pressurized digesters with chips, chemicals, and steam, thus bringing a batch digester on line faster.
- Replacing an existing mill or pulverizer (*e.g.*, grinding clinker in a

[7] As discussed in more detail below, although such activities would be functionally equivalent, they would still need to meet other criteria to qualify for the ERP. For example, a functionally equivalent replacement does not qualify for the ERP if it results in a change to a basic design parameter of the affected unit. If an activity does not qualify for RMRR under the ERP, the case-by-case RMRR approach would still be available to the owner or operator under those circumstances. And, of course, even if the activity does not qualify for the RMRR exclusion, the activity will not be a modification and, hence, will not trigger NSR unless it results in a significant emissions increase.

cement factory or coal for a boiler) with a new one of a different type because both new and old equipment serve the same purpose (even if the characteristics of the ground material would be different before and after the replacement).

• Replacing existing spray paint nozzles with new ones that might atomize the spray better or have a higher transfer efficiency because the ''before'' and ''after'' nozzles serve the same function.

At the same time, there are numerous activities that occur at facilities that may fall within the bounds of the cost threshold percentage, basic design parameters, and other backstop features of today's rule, but nevertheless cannot qualify for the RMRR exclusion on the grounds that the equipment is neither identical nor functionally equivalent. An example of this would be a chemical processing facility where the owner or operator makes a physical change that allows the production of a new end product that physically could not have been manufactured with the previous equipment using the same raw materials as used before in the same amounts as before. This would not be a functionally equivalent replacement activity because the facility is able to produce an end product after making the change that the facility was not capable of making before the change. Consequently, this activity would not qualify as RMRR under today's ERP.

Several commenters said the equipment replacement provision will streamline the major NSR applicability analysis. A number of commenters believed the ERP would be easier to implement than the proposed annual maintenance, repair and replacement allowance approach. One commenter said that allowing identical replacements to be excluded from major NSR will codify existing industrial practices, where replacement has no impact on emissions and would clearly represent RMRR.

Many commenters expressed support for the ERP, but recommended certain changes that they felt needed to be made to improve the proposal. One commenter supported the ERP in combination with a capacity-based option, on the assumption that repair and maintenance is to be excluded as well as equipment replacement.

One commenter attempted to collect data from turbine customers and found that achieving a level of data collection necessary for the ERP was far from simple, because the cost of maintenance activities is affected by such things as variability in engine model, package technology, and type of maintenance contract. Another commenter gave an example of the benefit that the ERP may provide. Without the ERP, the commenter said the source is limited to some fraction of boiler tubes allowed to be replaced at a given time, whereas with the ERP, replacement of all boiler tubes would, in the commenter's opinion, rightfully be considered routine. Another commenter said the ERP will remove regulatory burdens for types of equipment replacements that are in their view ''routine,'' such as replacement of tubes in industrial boilers. They added that, without a clearer understanding of which activities are RMRR, they may be inclined to delay conducting such replacements.

Many other commenters generally opposed any change to the RMRR exclusion, including one based on equipment replacement. Some of these commenters believed the ERP was problematic because it would allow a source to replace an entire process unit over time. Two of the commenters opposed the ERP because they felt it would create disincentives for the implementation of Plantwide Applicability Limits (PAL) and Clean Unit provisions from the recently finalized rule.

One commenter said that from an engineering standpoint, for a power plant, the difference between routine maintenance and a major plant refurbishing project is clear. To further clarify, the commenter made the following points. According to the commenter, routine maintenance is frequent and follows a predictable pattern. The commenter characterized routine maintenance at power plants as: repair of leaking pipes, pumps, valves, and fans; cleaning and lubrication of components; and inspections. The commenter added that permanent staff do this work either while the plant is operating or during only brief periods of downtime. The commenter further expressed that activities that are not routine require long plant or process unit shutdowns, are done infrequently, and are major capital projects for which special funding is set aside as a result of years of planning and design work.

One commenter said the proposal will allow emissions increases that will be difficult to offset through other regulations. One commenter objected to the ERP for a number of reasons: (1) The provision does not prevent replacement with different equipment; (2) it does not promote efficiency improvements or application of good air pollution controls; and (3) it would allow replacements that would significantly increase emissions. This commenter said replacement of air pollution controls should trigger best available control technology (BACT) or lowest achievable emission rate (LAER) requirements. Two local air pollution control agencies in California noted that they currently already exclude all replacements with identical equipment from major NSR when certain conditions are met.

Commenters generally had similar viewpoints on allowing both identical and functionally equivalent equipment replacements to qualify as RMRR. However, some commenters expressed greater concern related to excluding the replacement of equipment with functionally equivalent equipment. Primarily their concerns were rooted in the fact that a functionally equivalent replacement component could lead to increases in operational efficiency or productivity, and these commenters asserted that these sorts of process enhancements should not be excluded as RMRR.

We agree with the commenters who felt identical and functionally equivalent replacement activities generally should be excluded as RMRR. We also agree with the commenters who believe that this provision will streamline the major NSR applicability process and will bring clarity. The provision we are finalizing will allow a source to make a simple determination as to whether a replacement piece of equipment qualifies as identical or functionally equivalent. This type of determination will be straightforward and easier for the source to implement than the current case-by-case analysis required to determine a replacement falls within the RMRR exclusion. We support the air pollution agencies that have already excluded these types of changes from NSR.

We disagree with those commenters who believe that this provision will create disincentives for sources to accept a PAL or have emission units designated as Clean Units. A PAL offers a source to bring on entirely new emissions units with no Federal preconstruction permit, as long as emissions caps are not exceeded. A PAL or a Clean Unit designation allows a source to make modifications without performing a major NSR applicability test. These advantages will still be the driving force for sources to elect to use the PAL or Clean Unit provisions, and we do not believe this final rule will significantly detract from their appeal.

We also believe that there is substantial value in facilitating equipment replacements to a greater degree than our current approach permits and draws a cleaner and more

easily administered line between equipment replacements that categorically do not require a permit and major plant refurbishing which will result in increased emissions. For pieces of equipment used at industrial facilities, most manufacturers have well-established procedures for the inspection and replacement that are part of the regular maintenance necessary to provide for the equipment's safe, efficient and reliable operation. Some of these replacements are large in terms of cost and infrequent, but all are necessary to maintain the safe, efficient and reliable use of the process unit. We believe it is important to allow for these replacements provided that certain safeguards are in place, as discussed below.

We disagree with suggestions from commenters that the time period between activities, standing alone, provides an appropriate or clear distinction between activities that should be permissible under the RMRR exclusion and those that should not. In fact, some components wear out every year, while others wear out every 20 years. Nevertheless, both types of changes should fall within the ERP of the RMRR exclusion because both allow the facility to operate as designed. By not imposing a time limitation, the ERP allows replacement activities to be driven by consideration of economic efficiency rather than artificial regulatory constraints.

We disagree with commenters who expressed particular concern about functionally equivalent replacements. We continue to believe such activities should be encouraged and should qualify as RMRR. Even though a functionally equivalent component varies in some respects from the replaced component, we feel the most important factor to consider is whether the replacement will serve the same purpose as the replaced component. We acknowledge that a functionally equivalent replacement can result in an increase in efficiency and, consequently, productivity. In fact, one of our goals is to promote such outcomes. However, we believe that the basic design parameter safeguard is appropriate to assure that the ERP only automatically excludes from major NSR functionally equivalent replacements that do not result in a significant change to the fundamental characteristics of the process unit.

We note that the two local programs in California that exclude the replacement of equipment with identical equipment also allow the replacement of equipment with functionally equivalent equipment without considering such action to be a modification. Due to local air quality considerations, the local programs establish minimum pollution control requirements that are imposed in some circumstances when functionally equivalent equipment replacements occur. Nothing in today's rule would prevent a State or local program from imposing additional requirements necessary to meet Federal, State or local air quality goals.

After reviewing the comments on our proposal, we have decided to promulgate what we proposed in December 2002 for the RMRR equipment replacement provision with relatively minor changes. We decided to include another safeguard in addition to those we proposed in order to appropriately constrain the meaning of the term ''functionally equivalent.'' The additional safeguard is that an excluded replacement activity cannot cause the process unit to exceed any emission limitation or operational limitation (that has the effect of constraining emissions) that applies to the process unit and that is legally enforceable.

Thus, today's final rule allows you to categorize identical and functionally equivalent equipment replacements as RMRR if the fixed capital cost of such replacement plus the cost of repair and maintenance activities that are part of the replacement activity does not exceed 20 percent of the replacement value of the process unit, and if the replacement does not alter a basic design parameter of the process unit or cause the process unit to exceed any emission limitation or operational limitation (that has the effect of constraining emissions) that applies to the process unit.

C. What Cost Limit Has Been Placed on the Equipment Replacement Approach?

The next concept presented in the proposal is the cost-based limitation on the scope of the ERP. The purpose of this threshold is to distinguish between those equipment replacement activities that should automatically qualify as RMRR without further consideration and those activities that should undergo case-specific consideration. This concept is akin to the long-established reconstruction provision under the NSPS program. For the reasons explained below, we have decided to establish a 20-percent cost threshold under the ERP.

We believe a similar bright-line rule that would obviate the need for case-by-case review under our multi-factor test of appropriate categories of equipment replacements would be extremely useful in addressing many of the problems that we have identified with the current operation of the NSR program. Such a rule would be particularly useful in avoiding the uncertainty and delay, and consequent postponed or foregone equipment replacements, that our multi-factor case-by-case review induces. For example, our RIA indicates that it takes a year, on average, to obtain a determination whether a proposed replacement is routine. That kind of delay obviously creates perverse disincentives to refrain from equipment replacements and instead repair existing equipment or find some other solution.

This is the kind of problem that classically leads agencies to fashion bright-line tests to provide greater regulatory certainty and efficiency. Moreover, because the kind of disincentives that give rise to this concern operate largely by economic means, prompting sources to take one course of action (cut back on productive equipment replacement) rather than another (replace the equipment and incur the costs of delay, as well as potentially the costs of installing state-of-the-art controls), we think a cost-based threshold is a reasonable basis on which to create such a bright-line rule.

In the proposal, we observed that it may sometimes be difficult to determine where to draw the line between an activity that should be treated as an excluded replacement activity and one that should be viewed as a physical change that might constitute a major modification, when the replacement of equipment with identical or functionally equivalent equipment involves a large portion of an existing process unit. We solicited comment on a range of equipment replacement cost thresholds such as one based on the NSPS program. Under the NSPS program, when the cost of a project at an existing affected facility exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new unit (that is, the current capital replacement value of the existing affected source), then the source must notify and provide information to the permitting authority. After considering a range of factors, including the cost of the activity, the estimated life of the facility after the replacements, the extent to which the replaced equipment causes or contributes to the emissions from the source, and any economic or technical limitations on compliance with the NSPS, the reviewing authority

determines whether the proposed project is a reconstruction.[8]

We observed that, in some respects, an equipment replacement cost threshold set at the NSPS reconstruction test could be an appropriate approach for distinguishing between routine and nonroutine identical and functionally equivalent replacements under the major NSR program. As under the NSPS program, we do not believe it is reasonable to exclude from major NSR those activities that involve the total replacement of an existing entire process unit.

We also noted, however, that there are other considerations pointing in favor of a threshold lower than the 50-percent reconstruction threshold that might be appropriate to bound the ERP. Under NSPS, when a source undertakes a replacement activity at an existing affected facility that constitutes half or more of the facility's capital replacement value, our rules require a case-by-case determination as to whether such replacements constitute construction. We noted that a percentage threshold lower than 50 percent might be more appropriate for determining where we would require case-by-case consideration of the question whether equipment replacements constitute a modification of an existing process unit under major NSR. We solicited comments on the appropriate level of any percentage.

Many commenters supported the threshold of 50 percent of replacement value as the upper limit on equipment replacement. They felt this number is consistent with existing regulatory requirements and would accord the flexibility originally intended under the CAA for RMRR activities, while at the same time assuring that major, nonroutine projects remain subject to major NSR applicability review, and they felt this number is consistent with a common-sense interpretation of the regulations.

They also believed a 50-percent cutoff to be consistent with reconstruction definitions used in many NSPS and National Emission Standards for Hazardous Air Pollutants regulations. Some commenters stated that a 50-percent cutoff for the ERP would be valid for the same reason as for the NSPS reconstruction test; significant changes to a process unit are necessary before retrofit controls should be considered, provided there is no increase in emissions.

Many other commenters opposed the 50-percent replacement value threshold. They believed the capital replacement percentage should be much less than 50 percent. One commenter suggested as an appropriate threshold that the sum of equipment replacement costs for a single process unit over any period of 5 consecutive years should not exceed 50 percent of the replacement value of the process unit. Another commenter said the replacement percentage should not be higher than 25 percent. Another commenter suggested a replacement percentage of 5 to 10 percent to reduce the risk of replacement of an entire process unit over time without installation of BACT. One commenter said a more appropriate percentage for electricity producers is 0.1 to 1.0 percent. Another commenter said the threshold should be 5 percent, 1 percent, or even less, as shown by an NSR enforcement case against the Tennessee Valley Authority (TVA).

Another commenter believed the 50-percent number has no practical effect in protecting public health and the environment, and the commenter was not aware of any projects that have exceeded 50 percent in cost.

While opposed to the ERP in general, one commenter said the cost threshold should be as high a percentage as possible, so as not to promote premature replacement of equipment that is repairable. Another commenter said the 50-percent number from the NSPS is archaic and not environmentally protective. This commenter suggested that the threshold instead be 24 percent. The commenter believed this lower percentage is appropriate because the lifetime of high-cost materials will considerably exceed 5 years.

We agree with those commenters who see a relationship between establishing a threshold for equipment replacements that we will treat as RMRR under the major NSR program and the threshold the NSPS program established for reconstruction. However, we disagree that these two thresholds should be the same. The NSPS threshold was intended to identify those activities that, even though they did not qualify as a modification under NSPS, nevertheless are of such magnitude that further consideration should be given as to whether they are projects tantamount to new construction. The 50-percent NSPS threshold is not a bright line in the sense that all projects that exceed 50 percent are automatically considered as reconstruction. Rather, as discussed above, it is a threshold intended to alert permitting authorities to significant projects and allow case-by-case decisions based on a series of regulatory factors.

The ERP replicates the NSPS concept in some ways. It identifies a threshold below which there is no need for further inquiry into whether an activity qualifies for the ERP and above which there is a need for a case-by-case determination. The major difference between the ERP and the NSPS reconstruction test is that the ERP deals with modifications, not reconstructions. This difference weighs in favor of establishing the equipment replacement threshold at something less than the reconstruction threshold. It is logical and practical to conclude, as some of the commenters do, that by using the word ''modification'' the CAA intended to capture activities on a smaller scale than reconstructions. As noted above, we have set the ERP cost threshold at 20 percent. This value is less than one-half of the 50-percent reconstruction threshold and, therefore, fits well within this conceptual framework.

A 20-percent cost threshold would be consistent with the decision of the U.S. Court of Appeals for the Seventh Circuit in the *Wisconsin Electric Power Company* v. *Reilly* (''WEPCO'') case, to the extent that it would not automatically allow the activities performed there to constitute RMRR. See 893 F.2d 901 (7th Cir. 1990). This court decision directly addressed the question of what level of ''like kind'' replacement activities qualify as changes under the major NSR program.

In the *WEPCO* case, the Court considered an activity involving 5 coal-fired units at WEPCO's Port Washington plant. Each unit was rated at 80 megawatts of electrical output capacity. The activity involved the replacement of numerous major components. The information submitted by WEPCO showed that the company intended to replace several components that are essential to the operation of the Port Washington plant. In particular, WEPCO sought to replace the rear steam drums on the boilers at units 2, 3, 4, and 5. According to WEPCO, these steam drums were a type of ''header'' for the collection and distribution of steam and/or water within the boilers. WEPCO viewed their replacement as necessary to continue operation of the units in a safe condition. In addition, at each of the emissions units, WEPCO planned to repair or replace several other integral components, including replacement of the air heaters at units 1, 2, 3, and 4. WEPCO also planned to renovate major mechanical and electrical auxiliary systems and common plant support facilities. WEPCO intended to perform

[8] In the proposal, it was incorrectly stated that applicability of the NSPS was triggered if a project exceeded 50 percent of the cost of replacing the affected facility. As stated in this notice, if an activity exceeds this cost threshold, that only triggers further evaluation, not the automatic application of the NSPS to the source.

the work over a 4-year period, utilizing successive 9-month outages at each unit. The cost of the activity was estimated in 1988 to be $87.5 million. The Court noted that EPA concluded at the time this activity was unprecedented in that EPA did not find a single instance of renovation work at any electric utility generating station that approached this activity in nature, scope and extent. The Court determined, at our urging, that the changes did constitute a ''physical change'' under the NSR rules.

In the case of a steam electric generating facility, the process unit definition provided in today's rule is nearly identical to the make-up of the ''comparable new facility'' that was used in the NSPS evaluation of the WEPCO renovation project. However, under our rule we would not include the cost of pollution control equipment in determining the replacement cost of the WEPCO process units. WEPCO had electrostatic precipitators on each of its 5 process units, which our rule would subtract from the replacement cost. In addition, the WEPCO evaluation dealt with 5 boilers, each with its own turbine-generator set; to be consistent with today's definition of steam electric generating facility, we would likely treat each boiler unit as belonging to a different process unit. However, since all of the boilers underwent similar renovations, for simplicity we can assume that all of the process unit-specific activity costs are equivalent.

Using 1991 dollars, consistent with the timeframe of the Seventh Circuit Court's decision, it appears that the value of the 5 process units at the 400-megawatt WEPCO Port Washington facility would be approximately $321 million based on 1991 model plant values provided by the International Energy Agency. The 1988 project cost of $87.5 million scaled up to 1991 dollars would have had an adjusted project cost of $92.3 million.[9] Thus, the capital cost percentage for the replacement activities at WEPCO, averaged over its 5 process units, amounted to 29 percent. Alternatively, using the project cost of ''at least $70.5 million'' cited in the 1991 decision by the Seventh Circuit, and using the same value for process unit cost, we compute at least 22 percent. The 20-percent threshold is, therefore, beneath the scope of the activities at issue in the *WEPCO* case and hence not inconsistent with that decision.

[9] Using the Chemical Engineering magazine's Annual Plant Cost Index (composite), $87.5 million in 1988 dollars is equal in real terms to (361.3/342.5) multiplied by 87.5 million, or $92.3 million in 1991 dollars.

The 20-percent threshold also is supported by available data for the electric utility sector. We have a robust and detailed set of information available on maintenance, repair and replacement activities for the electric utility sector. Information about the electric utility sector persuades us that we have established the right ERP threshold for this sector.

Information on other industrial sectors beyond electric utilities (as well as general economic theory) further supports our 20 percent bright line test. Case studies performed by an EPA contractor and included in Appendix C of our final regulatory impacts analysis (RIA) estimate the overall impact of the rule on six different industrial sectors (pulp and paper mills, automobile manufacturing, natural gas transmission, carbon black manufacturing, pharmaceutical manufacturing, and petroleum refining). The case studies find that routine equipment replacement activities generally do not cause emissions increases. The case studies also find that equipment replacement activities vary widely within these industries. Likewise, the cost of these activities as a percent of the process unit replacement value varies widely. We recognize that the study addresses specific case examples from only a part of regulated industry and that the project cost information is derived from a limited inquiry of industry representatives. We believe, however, that the study provides a useful scoping assessment that tends to support the proposition that the 20 percent threshold derived for the utility industry (which is based on robust industry data) should be applied to industry as a whole. In short, the study supports our view that it is reasonable to assume that equipment replacement activities in the utility industry are similar enough to replacement practices in other industry that the 20 percent value determined for utilities, is appropriate for industry as a whole. This data indicates that most typical replacement activities will fall within the 20-percent threshold. At the same time, the data indicates that some major replacement activities likely will cross the 20-percent threshold and will require a case-by-case evaluation under the multi-factor RMRR test.

Two comment letters (from the Utility Air Regulatory Group (UARG) and from the American Lung Association (ALA), *et al.*) were particularly helpful in understanding the issues associated with the electric utility sector. The UARG provided as an attachment to its comment letter a document describing major repair and replacement activities that its members believe must be undertaken at utility generating stations in order to keep those facilities operational. The UARG noted that capital costs incurred for repair and replacement activities at an individual process unit additionally include activities more minor than those addressed in the document. The UARG grouped repair and replacement activities into project families; within each project family were per-component costs ($/kW) for numerous equipment replacement activities. We have reviewed the list of projects supplied by UARG and have concluded that these types of replacement activities are important to maintaining, facilitating, restoring or improving the safety, reliability, availability, or efficiency of process units. Therefore, generally speaking, these types of individual activities and groups of activities should qualify for the ERP and be excluded from major NSR without case-specific review. We also believe that it is reasonably expected in the electric utility industry for groups of these activities to be implemented at the same time. Such groupings should also be excluded without case-specific review. When we compare the 20-percent ERP cost percentage to the UARG data, we find that individual replacement activities would, in fact, qualify for the ERP and that limited groupings of these activities would qualify. However, larger groupings of these activities—groupings that are not usually seen in the industry—would not qualify for the ERP. This shows that the 20-percent threshold will be effective in distinguishing between activities (and aggregations of activities) that should not require case-specific review to be excluded from major NSR and those that do.

The ALA commenters provided with their comments the results of their analysis of projects at issue in an NSR enforcement case against Tennessee Valley Authority (TVA). As shown in the ALA comment letter, the Clean Air Task Force and the Natural Resources Defense Council looked at costs for 14 projects on a process unit basis, in year 2001 dollars, from the publicly available record for the case. For all but one of the challenged projects, the ALA commenters calculated a cost of less than 4 percent of process unit replacement cost. The ALA commenters submitted results of this analysis with their opposition to a source-wide, 5-percent maintenance allowance. As noted above, we concluded in our 2002 report to the President that the NSR

program—and the RMRR provision in particular—has in fact resulted in delay or cancellation of activities that would have maintained and improved the reliability, efficiency, and safety of existing energy capacity. The primary purpose of today's rule is to rectify this problem. Thus, to the extent the activities addressed by ALA qualify for the ERP, we now believe that such activities, if conducted in the future, should be excluded from major NSR.

A final factor that we believe supports our selection of a 20 percent threshold is the cost of installing state-of-the-art controls on existing units. There is obviously no single answer to the question of at what point that cost becomes the deciding factor in an owner's decision whether to replace a piece of equipment and incur that cost, since much will depend on the rate of return on the investment. Nevertheless, we think it is reasonable to assume that if the cost of the controls is greater than the cost of the replaced equipment, it is likely to operate as a substantial deterrent to replacing the equipment at issue. That is likely to be the case with respect to electric utilities if we set the threshold below 20 percent, which represents the approximate cost of retrofitting existing plants with state-of-the-art controls. The equation is similar for industrial boilers. Notably, those sectors represent a substantial fraction of the emissions potentially subject to the NSR program. While the relative costs of air pollution controls in other industries vary more widely than the costs for utility and industrial boilers, we nevertheless believe that the costs and technical issues associated with retrofitting air pollution controls factor significantly into equipment replacement decisions.

D. What Will Be the Basis of Applying the 20-Percent Threshold?

In the proposal, we solicited comment on whether implementing the ERP on a per-activity basis or on some other reasoned basis, such as applying the percentage to components that are replaced collectively over a fixed period of time, may be more workable.

Many commenters stated that the ERP should be implemented on a per-activity (or aggregation of activities) basis. Two of the commenters cited longstanding NSR precedent as the basis of their comments, while two other commenters relied on NSPS precedent. Another commenter thought the per-activity approach would be less confusing than summing activities over a fixed period of time. Other commenters believed the equipment replacement threshold should in fact be applied on a 5-year rolling average.

We have decided to apply the percentage threshold on a per-activity (or aggregation of activities) basis. This is consistent with how major NSR has been applied in the past and will continue to apply in the future, with the exception of those sources which establish a PAL. The major NSR program is a preconstruction program that requires applicability to be determined for a given activity at a facility and, as necessary, permitting to occur prior to the time activities are commenced. The major NSR program also requires applicability to be determined, in the first instance, based on an assessment only of the parts of a facility involved in the activity. A per-activity basis works well with this approach. We are not going final with a ''component-by-component'' approach that we solicited comment on through our RMRR proposal.

There would be obvious problems if we chose any of the other approaches suggested in the proposal or suggested by commenters (for example, annual basis or 5-year rolling average). One of the primary concerns with applying the percentage to activities performed over a span of time is that we would be restructuring the major NSR program to operate based on after-the-fact determinations. This raises the difficult question of what happens under this type of approach if you learn after commencement of an activity that it does not qualify under the ERP. This situation is largely avoided by the per-activity approach that we are establishing in today's rule.

It should be noted that activities that are related must be aggregated under the ERP, in the same way as they would have to be aggregated for other NSR applicability purposes. Under our current policy of aggregation, two or more replacement activities that occur at the same time are not automatically considered a single activity solely because they happen at the same time. For example, a steam turbine rotor replacement project and a boiler tube replacement project would not be aggregated simply because they occur during the same maintenance outage and on the same process unit. Further inquiry into the nature of the activities and their relationship to each other is needed before deciding whether the activities must be aggregated under NSR. Also, non-replacement activities that are part of a larger replacement activity should be included when calculating costs for a replacement activity against the capital cost threshold.

E. What Basic Design Parameters Are Being Established To Qualify for the Equipment Replacement Provision?

In the proposal, equipment replacements were only eligible for the ERP if they did not change the basic design parameters of the process unit. We proposed that maximum heat input and fuel consumption specifications for EUSGUs and maximum material/fuel input specifications for other types of process units are basic design parameters. We solicited comments on limiting the eligibility of the ERP this way and on the basic design parameters we proposed.

Several commenters expressed concerns with either the use of these specific parameters, or the restriction of the regulated community to only this set of design parameters. Other comments centered around an inconsistency in how EPA has accounted for efficiency in the basic design parameter safeguard. The commenters stated that, while EPA stated in the proposed preamble that efficiency is not a basic design parameter, the basic design parameter safeguard, as proposed, has the potential to bar equipment replacements that achieve significant gains in efficiency.

Commenters from all sides supported EPA's approach to handling activities intended to improve an affected process unit's performance beyond its basic design parameters. Commenters asserted that these actions would not fall within the RMRR exclusion. Commenters from the gas transmission industry concurred and amplified this concept, stating that an engine that is ''uprated'' at the time of overhaul should not be excluded from major NSR under the RMRR exclusion.

We recognize that the proposed basic design parameters are inconsistent with some industry conventions, and that we should allow for industry-specific flexibility or specify additional source category-specific parameters. For example, for natural gas transmission compressor stations, commenters explained that brake horsepower is the conventional design capacity parameter. We received similar comments from other industries, including cement and surface coaters, who objected to limiting their facilities to the proposed basic design parameters. Accordingly, we have decided to provide flexibility by providing a menu of choices from which the owners or operators may select and also by allowing for owners or operators to propose alternative basic design parameters to their reviewing authority which would then be made legally enforceable.

In addition to this flexibility, there may be a need for additional flexibility in using the basic design parameters that are spelled out in today's rule. For instance with boilers, maximum steam production rate is often used by the industry, and it may make sense in some cases to set the design parameters based on those values rather than on maximum heat input. Likewise, a crude oil distillation tower may have several capacities that are a function of the type of crude that is to be processed, and so a refiner may need to have a set of basic design parameters for its crude towers. These situations can be addressed by the source proposing alternative parameters or sets of parameters to their reviewing authority.

Also, there should be flexibility in how the basic design parameters are demonstrated when the owner or operator chooses not to rely on the design information for its process unit. For example, in order to establish the heat input value that the process unit has demonstrated it is capable of achieving, an electric generating unit should have the flexibility to reference available credible information, such as results of historic maximum capability tests or engineering calculations. Results from tests performed by electric utilities in the context of providing assurances to generation dispatch systems and regional or national power pools may be used to establish the process unit's maximum heat input. A review of such data or other available operational data or design information can reveal the heat input that the process unit is capable of achieving in its ''pre-activity'' configuration, and this can be compared to a ''post-activity'' heat input value. Plant operators, where the specified basic design parameters are inappropriate for the process, can propose what the measure of performance will be for these process units, including the use of permit limits on amount of production, to their reviewing authority. For process units having multiple end products and raw materials, the owner or operator should consider the primary product or primary raw material when selecting a basic design parameter.

Many pieces of equipment are purchased based on their capacity or output. Consequently, for both utilities and non-utilities, we have modified the proposed basic design parameters to include output-based alternatives in today's final rule. For utilities, the owner or operator can select maximum hourly electric output rate and maximum steam flow rate as its basic design parameters, as an alternative to using input-based measures of maximum hourly fuel consumption rate and maximum hourly heat input. (We are clarifying from the proposal that the correct parameter is maximum hourly heat input, not maximum heat input.) Owners or operators may set different design parameters for different fuel types (such as coal or oil) or a combustion device that can accommodate multiple fuel types: for coal-fired units, owners or operators should consider that the fuel consumption rate will vary depending on the quality of the coal for a given heat input. When establishing fuel consumption specifications in terms of weight or volume, the minimum fuel quality based on BTU content should be used for coal-fired units.

Regardless of whether the source selects a basic design parameter(s) specified for non-utilities in today's rule or gets approval from their reviewing authority to use an alternative parameter(s) for any type of source, we have not specified a fixed averaging time period for the circumstance because we want the owner or operator to have the flexibility to select an averaging time that best accommodates their operation. In most cases, we believe that long term averaging periods (*e.g.,* a 12-month fixed period) will not be appropriate.

Thus, an equipment replacement that improves a process unit's efficiency and thereby enables the unit to return to its design parameters can qualify as RMRR even if current actual emissions increase as a result. For example, if boiler tubes or refractories are replaced on a boiler process unit, and these activities are beneath the capital cost threshold and are within the unit's basic design parameters, then they would qualify as RMRR under the ERP even if this improves the unit's efficiency.

The manufacturer's design parameters of a process unit are always acceptable if an owner or operator chooses to rely on them. In the rare cases where a facility does not have established design parameters, we believe that a reasonable look back period should be used for establishing the pre-activity values for basic design parameters, rather than taking the condition of the process unit immediately before the activity. We have therefore established a 5-year look back period, consistent with that for the NSPS hourly emissions increase test, for these situations.

We were urged by some commenters to incorporate a *de minimis* increase level in the basic design parameters that would allow activities to qualify for the ERP even though the activities would result in a minor change to the relevant basic design parameters. They argued that some effects resulting from the replacement may not be apparent before the equipment has been replaced. They argued that allowing for small changes in basic design parameters would add greater certainty to the ERP because unforeseen small changes would not cause an activity to lose the exclusion after the fact. While we sympathize with the commenter's concern, we do not see a ready solution to this problem under the RMRR exclusion. In fact, we are not persuaded that those types of changes can be readily justified under the ERP because it is hard to see how an activity that causes basic design parameters to change is not ''a change'' under NSR.

In sum, we continue to believe that an identical or functionally equivalent replacement should not qualify for the ERP if the activity causes the process unit to exceed its specified basic design parameters. Without such a requirement, significant alteration of a process unit's fundamental design could be accomplished under the guise of the ERP. Such an outcome obviously does not square with the idea that identical or functionally equivalent replacements are not ''changes'' under the major NSR program. Our final rule is different from the proposal, however, in that it provides greater flexibility in defining basic design parameters for process units. We were persuaded by commenters who expressed concerns that the proposed approaches did not adequately encompass all affected operations and industry sectors.

F. What Collection of Equipment Should Be Considered in Applying the Equipment Replacement Provision and How Should It Be Defined?

In the proposal, we raised the issue of what collection of equipment should be considered in applying the threshold under the ERP. We proposed the term ''process unit'' as the appropriate collection to accommodate the intended coverage of activities under the ERP. The purpose of this term is, to the extent possible, to align implementation of the ERP with generally accepted and practical understandings of what constitutes a discrete production process. The general definition that we proposed was based closely on the definition of process unit contained in 40 CFR 63.41 and read as follows:

> Process unit means any collection of structures and/or equipment that processes, assembles, applies, blends, or otherwise uses material inputs to produce or store a completed product. A single facility may contain more than one process unit.

To help illustrate these concepts, we further proposed five industry-specific

examples of how this definition of process unit might be applied.

Some commenters compared the proposal's definition of ''process unit'' (''* * * producing or storing a completed product * * *'') to the definition that is used by section 112(g) and that appears in 40 CFR 63.41 ('' * * * producing or storing an intermediate or final product * * *''). One of the commenters supported the proposed definition. Two commenters said the rule's definition should be consistent with that used by section 112(g), which they believe is broad enough to encompass interrelated operations. While supporting the RMRR proposal's definition, two commenters recommended that EPA provide regulatory flexibility by allowing a facility the option to choose which definition it will use.

One commenter generally supported the proposed definition of ''process unit,'' but this commenter believed that ''the delineation of a process unit should be made by regulated entity rather than explicitly defined in a rule.''

Three commenters asserted that pollution control equipment should be included in the process unit definition. One industry commenter said pollution control equipment is often integral to the process and may produce an intermediate product. One environmental commenter believed the proposed rule was unclear as to whether pollution control equipment is part of the process unit.

Several commenters said the proposed definition is too vague or broad. Another commenter urged EPA to change the definition of process unit to limit the scope of what is allowed in the ERP, so that the source of emissions (for example, an entire coal boiler) would not be allowed to be replaced without major NSR. The commenter asserted that the replacement unit's scope should be limited to an emission unit.

Most commenters agreed that the general process unit definition is sufficient. However, a number of commenters suggested that we revise or eliminate some of the process unit examples (that is, the industry category-specific definitions), and others were concerned that the proposed definitions do not support the detailed process unit definition for a specific industry because the definitions will never capture all possible elements and configurations.

We received comments from several industry representatives suggesting changes to our proposed industry-specific definitions, and also to request that we delineate other process unit types explicitly in the rule. Definitions were submitted for sugar mills, chemical manufacturing plants, surface coating operations, flat glass manufacturing, fiberglass manufacturing, and gas compressor stations.

One industry commenter agreed with our proposed approach to proportionately allocate, based on capacity, the cost of those components shared by two or more process units. Another commenter suggested that, for electric utilities, we allocate the cost of shared equipment based on a *pro rata* share of megawatts produced.

We agree with the commenters who favor using a process unit as the basis for administering the ERP and including a definition of process unit in the final rule. We also agree with the commenters who suggested that the definition of process unit should be consistent with the definition in 40 CFR 63.41, and we have altered the final rule definition to include those processes that produce ''intermediates.'' We acknowledge that, without further explanation, the term ''intermediates'' is susceptible to misinterpretation, which can cause confusion and lead to less regulatory certainty. Thus, we provide the following explanation as to how we intend to interpret today's rule.

By ''intermediates,'' we mean the intended product of an integrated facility operation. For example, for an automotive manufacturing plant, while the completed product would be the driveable vehicle ready for shipping to the showroom, an intermediate product could be the engine or the painted body shell. In this case, we would not consider smaller production operations, such as the e-coat, primer surface, or top coat operation, to be intermediates in the context of our final rule definition for process unit. Our primary goal in defining this term ''process unit'' is to encompass integrated manufacturing operations that produce a completed product, and those operations that produce an intermediate as the product of the process unit. In the case of the automotive paint shop, series of coating steps together comprise the carefully designed and interrelated set of operations, all of which are needed to provide a coating system that meets design specifications. The individual operations almost never are implemented individually and, as a practical matter, simply would serve no meaningful purpose in the absence of the others.

We disagree with the commenters who wish to include all pollution control equipment in the definition of process unit. We feel that periodic replacement of components of emissions control equipment should be encouraged and would rarely lead to actual emissions increases. In instances where identical or functionally equivalent replacement of pollution control equipment occurs, it is likely you will qualify for a Pollution Control Project exclusion. We do agree, however, that where the control equipment is an integral component of the process it should be included. Therefore, we are excluding associated pollution control equipment from the definition of the ''process unit,'' except for control equipment that serves a dual purpose in the process. We know there are industries where pollution control equipment performs a dual purpose; for example, condensers often serve to control emissions of organic air pollutants while serving as an integral component of the operation of a fractionation column. A low-NO_X burner is another example of a dual-purpose component. In such cases, to provide clarity and simplify administration of the ERP, our rule provides that dual purpose equipment should be considered part of the process. We are also clarifying in today's rule that administrative buildings (including warehousing) are not to be included in the process unit, but other types of non-emitting units that are integral to the processing equipment should be included.

We also have included in our final rule industry-specific examples of how this definition might be applied. The examples are drawn from three selected industrial processing categories—electric utilities, refineries, and incinerators. We proposed each of these detailed definitions and received mostly support from commenters on their accuracy. While we also proposed detailed definitions for two other industries—pulp and paper and cement producers—we have decided not to finalize those definitions after receiving comments from the relevant industry trade association asserting that the definitions did not, and could not, capture all of their industry's configurations and they believed the generic process unit definition was sufficient for their industry. Because of the centrality of the ''process unit'' concept to the usefulness of the ERP, it is our desire to include specific definitions for steam electric generating facilities, petroleum refineries, and incinerators in the final rule to provide as much certainty as possible for facilities in these industries. As noted above, these definitions also should be useful for those in other industries who

will apply our general definition because the industry specific definitions provide clear examples of how we intend the general definition to be interpreted and applied. During the public comment period on the proposal, several commenters submitted additional industry specific definitions and asked us to put them in the final rule. We are not finalizing these suggested definitions at this time, because we did not include them in the proposed rule. However, provided below are the process unit definitions that commenters submitted to us and that we think comport well with the general definition of process unit promulgated today.

• For a *natural gas compressor station,* each compressor system, together with its proportionate share of common support equipment is a separate process unit. This would generally consist of the air inlet system, accessory drive system, gas producer, fuel delivery system, cooling system, lube system, power turbine, power shaft, control system, starting system, exhaust system, and support facilities (*e.g.*, auxiliary power generating equipment, heating/cooling equipment, station and yard pipe, valves, etc.).

• For a *flat glass manufacturing plant,* each production line within a facility should be a separate process unit. Flat glass production is completed on a continuous line where raw materials are added at one end, a continuous ribbon of glass is formed, and finished glass is packaged at the other end. The flat glass production line consists of: the batch house, where raw materials are stored and weighed; the furnace and refiner, where the raw materials are melted; the bath, where the glass ribbon is formed; the lehr, where the ribbon is annealed; and the cutting and packaging equipment, where the glass is removed from the line for sale to customers or for additional processing later.

• For a *fiberglass production facility,* each production line is a separate process unit. Fiberglass is manufactured on a continuous line where raw materials are melted at one end to form a continuous strand of fiberglass that is packaged at the other end. The fiberglass production line begins with the batch house, where raw materials are stored and weighed. In the melter, forehearth, and refiner, the raw materials are melted and refined. From the refiner, glass fibers are formed through controlled bushings. From the bushings, the continuous strand fibers are either directly cut or packaged or wound onto spools for packaging for sale to customers or for additional later processing.

• For the production of *precipitated amorphous silica,* the process unit includes, but is not limited to: raw material storage and handling equipment used for mixing sand and other raw materials prior to addition to the furnace; the furnace itself; the raw material storage and handling equipment for the cullet dissolving and silica precipitation process; all dissolving, precipitation, and filtration tanks and equipment; and drying equipment. Further, the process unit includes all the product packaging, storage, handling, and transfer equipment.

• For a *chemical manufacturing plant,* the process unit would include all the equipment assembled and connected by pipes or ducts to process raw materials and to manufacture an intended primary product and associated byproducts or intermediates. The process unit can consist of more than one unit operation. Chemical manufacturing process units may include, but are not limited to: raw material storage, and air oxidation reactors and their associated product separators and recovery devices; reactors and their associated product separators and recovery devices; distillation units and their associated distillate receivers and recovery devices; associated unit operations; associated recovery devices; and any feed, intermediate and product storage vessels, product transfer racks, and connected ducts and piping. A chemical manufacturing process unit includes pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, instrumentation systems, and process control or dual purpose air pollution control devices or systems. For a chemical manufacturing facility, there are several types of process units: those that separate and distill raw material feedstocks; those that change molecular structures through reactions or polymerization; those that ''finish'' the reacted or polymerized product, through compounding, blending, or similar operations; auxiliary facilities, such as boilers and by-product fuel production; and those that load, unload, blend, or store products. Process equipment that acts to control emissions, such as condensers, recovery devices, and oxidizers, is considered part of the process unit.

We note that we were unable to include some other process unit definitions submitted by commenters. While we do not believe that these other proposed definitions were necessarily inconsistent with our general definition of process unit, we had concerns and questions with some of these proposed definitions. We believe that now that this rule is issued, we can more fully evaluate those other definitions, including communicating with the leading industry officials, and determine whether we would approve of their use.

Finally, we have made some slight corrections to the process unit definitions that we proposed based on comments we received on the proposed definitions.

There are numerous industries that have industrial boilers at their facility to provide electricity and steam to their operations. As a general rule, we would expect these boilers to be treated as a separate process unit from the other unit operations occurring at the facility. We would expect the boundaries of the process units for such boilers to be consistent with the boundaries established under the definition for a steam electric generating facility in today's rule, which encompasses all equipment from coal handling to the emission stacks.

We also decided to continue to require that owners or operators who have components shared by two or more process units to proportionately allocate, based on capacity, the cost of those components. And we agree with the commenter that an equitable approach for electric utilities having components shared by two or more process units is to allocate the cost of shared equipment based on the *pro rata* share of megawatts produced by each process unit.

G. Consideration of Non-Emitting Units as Part of the Process Unit

Many commenters supported excluding non-emitting equipment from the ERP. One commenter stated that triggering the major NSR review process for maintenance activities is an impediment to continuous improvement projects for certain products and processes, even if actual emissions decrease or only non-emitting units on the process line are affected. Delays or postponements of project maintenance work adversely affect the reliability, safety and productivity of operations and cost control efforts. Another commenter recommended that work at clearly non-emitting units, specifically including foundation regrouting and repair and frametop replacement, should be excluded from this rule. Three commenters believed that non-emitting units cannot result in an

increase of emissions and thus do not need to be evaluated under major NSR.

A blanket exclusion for non-emitting units could create problems of interpretation because the term ''non-emitting components'' is ambiguous when considering certain components. Commenters asserted that identifying and separating out non-emitting components can be a complex undertaking, and may be contrary to the goal of a clear and straightforward option. One commenter provided the following examples: (1) Piping systems (although pipe connectors are a source of fugitive emissions, the pipe normally is not); and (2) structural supports for a process unit (separating out the cost of supports from an investment basis throughout a facility will be difficult).

Another commenter believed it would be difficult to separate the costs of emitting and non-emitting equipment when determining the cost of the process unit. The commenter also believed it would be difficult to determine allocation of shared equipment in the cost analysis.

We are concerned that, if owners or operators were allowed to strip away all of the non-emitting components from a process unit definition, it would create significant ambiguity in the rule and could result in significant variation in how the rule is applied to similar sources in different jurisdictions. In addition, we simply do not think it is practical or logical to separate ''non-emitting'' components of a process unit from ''emitting'' components. We believe that integrated manufacturing operations (that is, process units) typically include both types of equipment. Separating emitting from non-emitting equipment would create an artificial divide that contrasts sharply with physical and operational reality.

As noted above, however, we do believe that a distinction should be made between non-emitting equipment that is part of a process unit and non-emitting equipment that is functionally distinct from the process unit. For example, most production facilities have buildings or space to house administrative offices, such as offices for the plant accounting staff. Such non-emitting facilities should not be considered part of any process unit under today's rule.

H. What Is the Accounting Basis for the Process Unit?

In the proposal, the accounting basis for the ERP discussed was the same as for the NSPS reconstruction provision, which is the fixed capital cost that would be required to construct an entirely new unit. We also discussed for the annual maintenance, repair and replacement allowance using the invested cost of a unit as the accounting basis. We proposed that it would be appropriate to require that costs be calculated using an approach along the lines set out in the EPA Air Pollution Control Cost Manual (*http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf*). Finally, we solicited comment on whether the costs associated with the unanticipated shutdown of equipment, due to component failure or catastrophic failures such as explosions or fires, should be included in evaluating costs under the ERP.

In reviewing comments, we recognized that some commenters appeared to direct their comments on the accounting methods at the annual maintenance, repair and replacement allowance, and not necessarily the ERP. Often, we came to this conclusion simply by the way the commenters organized their comments, and not by any specific statements in the comment letter. However, since we asked for comment on the accounting approaches as they would be applied to both the annual maintenance, repair and replacement allowance and the ERP, we believe that comments that appeared to be dedicated to the annual maintenance, repair and replacement allowance should also apply to our evaluation of the accounting for the ERP, except in the case where the commenter specified that their comments on the proposed accounting methods applied only to the annual maintenance, repair and replacement allowance or the ERP. Likewise, for considering whether costs associated with unanticipated shutdown of equipment, we considered the comments to apply to both the ERP and the annual maintenance, repair and replacement allowance unless the commenter specifically noted that the comment should not be applied to both of the proposed rule provisions.

Most commenters asked for flexibility on whether a facility should use replacement value, invested cost or insurance valuation as the basis for the calculations. They felt that all were of equal merit and different ones would be available at different facilities so EPA should not prescribe only one type.

Most commenters did not support the sole use of the EPA Air Pollution Control Cost Manual (APCCM) to standardize calculations for replacement and repair costs for RMRR in general. Most commenters felt that the APCCM is a worthy reference for costing but also that sources should not be limited to only one manual, because a single manual is likely to have shortcomings and not be able to represent every situation.

Many commenters supported an exclusion of costs for unanticipated shutdowns and failures. They noted that strong incentives exist to avoid fires, explosions and other unanticipated equipment failures because of the risk of human injury and production interruptions and because of the expense involved in restoring lost capacity. As a result, they contend that a catastrophic event already penalizes the facility dramatically, but then to impose the case-by-case analysis would only exacerbate their troubles. They explained that failures take place occasionally and can result in a sudden, unplanned partial or total loss of equipment. When such a failure occurs at a natural gas compressor station, the turbine or engine concerned must be replaced immediately to avoid a disruption in gas supply. Other facilities may have similar pressures to maintain their product around the clock. Such replacement fits easily within most elements of the equipment replacement test. Commenters asserted that replacing a catastrophically failed turbine or engine is clearly ''routine,'' since companies will always replace such failures.

Other commenters, however, opposed an exclusion for unanticipated shutdowns and failures on the grounds that maintenance activities performed during forced outages are simply maintenance and should be considered as such, particularly given that the proposed RMRR rule approaches and the December 2002 final rules already have given the industry a number of exclusion options.

We are allowing sources to determine the applicability of today's rule on the basis of replacement value, with an option for sources to notify their reviewing authority in writing if they desire to use another option (for example, invested cost or insurance value where the insurance value covers only the complete replacement of the process unit). The equipment replacement cost should be based on the current replacement value of the entire process unit at the time of conducting the activity.

Typically, replacement value is more easily obtained than invested cost. Most manufacturers will have information concerning the replacement value of a process unit, because such costs are commonly used when evaluating various business scenarios relating to manufacturing costs. Also, use of replacement value is consistent with the NSPS provisions.

In addition to determining the replacement value of a process unit, in our final rule we allow for the use of several other accepted methods in different industries for estimating such values. Replacement values are the estimated value of replacing a unit and can be based on a current appraisal. In lieu of replacement cost, you can also use inflation-adjusted original investment, insurance limits if insured for full replacement of the unit, or other cost estimation techniques currently employed by the company, as long as the company follows GAAP and if approved by the reviewing authority.

A dollar-per-kilowatt rate for calculating costs may be appropriate for utilities. This model is specific to source and fuel type and is updated periodically. We allow sources to use insurance valuation methods such as the Handy-Whitman Index to determine replacement costs for electric utilities. Other sources to compute costs include the Nelson Refinery Construction Index Factors, Solomon Refinery Study, and licensors of the respective process unit (*e.g.*, Kellogg, UOP).

In order for a cost-based approach to be equitable, all owners or operators must include the same categories of expenses in both the process unit replacement value and the replacement activities sought to be excluded. Therefore, although the final rule does not mandate any particular approach, we believe it is generally appropriate to calculate costs using an approach similar to the elements of Total Capital Investment as defined in the APCCM. While the manual contains basic concepts that could be used to estimate total capital investment at a process unit, it is geared toward cost calculations for add-on control equipment. On the other hand, the underlying concepts are taken from work done by the American Association of Cost Engineers to define the components of cost calculations for all types of processes, not just emission control equipment. In certain cases, other manuals might make more sense depending on their circumstances.

Under the APCCM, total capital investment includes the costs required to purchase equipment, the costs of labor and materials for installing the equipment (direct installation costs), costs for site preparation and buildings, and certain other indirect installation costs. However, any costs that are part of the installation and maintenance of pollution control equipment should be excluded from the cost calculation, per our discussion in the previous section of this preamble. We believe equipment that serves a dual purpose of process equipment and control equipment (combustion equipment used to produce steam and to control hazardous air pollutant emissions, exhaust conditioning in the semiconductor industry, *etc.* should be considered process equipment.

Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include such costs as: engineering costs; construction and field expenses (costs for construction supervisory personnel, office personnel, rental of temporary offices, *etc.*); contractor fees (for construction and engineering firms involved in the activity); startup and performance test costs; and contingencies.

We believe there may be merit to the comments we received advocating a categorical exclusion for unanticipated shutdowns and failures of some kind. When such an outage occurs, there may be a real urgency to restore the plant to operation without forcing it to await the results of a permitting action or applicability determination. In the past, we have handled these situations with case-by-case consent orders; however, even that approach may lead to unnecessary delays. It may specifically be sensible to relaxing the 20 percent cost threshold limitation for such events because it is unlikely that sources would incur an outage to avoid controls. We did not propose such a stand-alone exclusion and hence we believe we should not act upon it at this time.

I. Enforcement

1. Compliance Assurance

We believe that the records developed and maintained in the ordinary course of business will provide the primary means of assuring compliance with today's rule. We know that, as a general rule, companies necessarily generate and keep records related to the types of projects covered by today's rule. For example, companies generally have comprehensive procedures by which funds are allocated to both capital and maintenance expense projects. Many of the records generated by these procedures are needed for tax accounting purposes and, by law, must be maintained for at least 6 years. Moreover, additional records must be maintained in industries regulated for other purposes, such as the energy sector (over 90 percent of which, by capacity, is subject to FERC regulation). Public utilities, licensees and natural gas companies that are subject to FERC jurisdiction must, unless they receive a waiver from the Commission, comply with extensive accounting and record retention requirements. They must keep financial information according to uniform systems of accounts that are set out in 18 CFR part 101 for public utilities and licensees, and 18 CFR part 201 for natural gas companies. These uniform systems of accounts include hundreds of specific accounts, including individual accounts for boiler plant equipment, engines and engine-driven generators, turbogenerator units, and hundreds of other asset, liability, cost and property items.

These companies also must retain records according to the schedules set forth in 18 CFR part 125 (for public utilities and licensees) and 18 CFR part 225 (for natural gas companies). The types of records that companies must keep include, for public utilities and licensees, for example, generation and output logs (records must be kept for 3 years), load records (3 years), gauge-reading reports (2 years), maintenance work orders and job orders showing entries for labor, materials and other charges in connection with maintenance and other work pertaining to utility operations (5 years), work order sheets for construction work in progress (5 years), appraisals and valuations made of utility property or investments (3 years), engineering records, drawings, and other supporting data for proposed or as-constructed utility facilities, including detail drawings and records of engineering studies (must be kept until facilities are retired), contracts or other agreements relating to services performed in connection with construction of utility plant (6 years after the plant is retired or sold), general and subsidiary ledgers (10 years), paid and canceled vouchers, and original bills and invoices for materials, services, *etc.* (5 years).

Altogether, these various sources of information provide more than reasonable assurance of compliance with today's rule. This is particularly true given EPA's broad authority to inspect affected facilities and require submission of compliance related data. Accordingly, we are not imposing any recordkeeping requirements in today's rule.

2. General Issues

Today's rule provides revisions to the major NSR program to specify categories of equipment replacement activities that we will consider RMRR in the future. As recognized by the U.S. Supreme Court, an agency may not promulgate retroactive rules absent express congressional authority. *See Bowen* v. *Georgetown Univ. Hosp.*, 488 U.S. 204,

208, 102 L. Ed. 2d 493, 109 S. Ct. 468 (1988). The CAA contains no such expressed grant of authority, and we do not intend by our actions today to create retroactive applicability for today's rule. 42 U.S.C. 7401 *et seq.* Today's rule applies only to conduct that occurs after the rule's effective date.

None of today's rule revisions apply to any changes that are the subject of existing enforcement actions that the Agency has brought and none constitute a defense thereto. Furthermore, prior applicability determinations on major modifications that result in control requirements in an NSR permit that currently applies to a source remain valid and enforceable as to that source.

As noted above, today we are changing the scope of the RMRR exclusion from the major NSR program by taking final action on the ERP. If you subsequently undertake an activity that does not meet the applicable provisions of these new alternatives and do not obtain a preconstruction permit if you are required to do so, you will be subject to any applicable enforcement provisions (including the possibility of citizens' suits) under the applicable sections of the CAA. Sanctions for violations of these provisions may include monetary penalties of up to $27,500 per day of violation, as well as the possibility of injunctive relief, which may include the requirement to install air pollution controls.

J. Quantitative Analysis

At proposal, we presented a quantitative analysis of the possible emissions consequences of the range of different approaches to the RMRR exclusion to evaluate if our policy conclusions are correct. Our analysis was conducted using the Integrated Planning Model (IPM). This analysis was done for electric utilities because we have a powerful model to perform such an analysis that we do not have for other industries. We stated that the results for electric utilities accurately reflect the trends we would see in other industries.

The IPM analyses of different scenarios showed that the breadth of the RMRR exclusion would have no practical impact on, let alone be the controlling factor in determining, the emissions reductions that will be achieved in the future under the major NSR program. The analyses showed that emissions of SO_2 are essentially the same under all scenarios, but that under today's rule these emission levels will be met in a more economically efficient manner than the base case. This stands to reason because nationwide emissions of SO_2 from the power sector are capped by the title IV Acid Rain Program. For NO_X, these analyses showed modest relative decreases in some cases and modest relative increases in other cases. These predicted changes represent only a fraction of nationwide NO_X emissions from the power sector, which hover around 4.3 million tons per year (tpy). At this time, we do not have adequate information to predict with confidence which modeled scenario is most likely to occur. What these analyses indicate, however, is that regardless of which scenario is closest to what comes to pass, today's rule will not have a significant impact, up or down, on emissions from the power sector. However, we expect the rule to result in significant improvements in safety, reliability, and other relevant operational parameters.

The DOE also presented further analysis of the possible emissions consequences of the range of different approaches to the RMRR exclusion. Using the National Energy Modeling System (NEMS), a variety of changes in energy efficiency and availability were evaluated, as well as the effect on emissions resulting from these regulatory revisions. This analysis concluded that efficiency improvements resulting from increased maintenance, repair and replacement are expected to decrease emissions, whereas availability improvements are expected to increase emissions. In the cases represented in this analysis, the emissions reductions from assumed reductions in heat rates tended to dominate the corresponding effects of the assumed availability increases.

A number of commenters said that the underlying assumptions EPA used in the IPM analysis were flawed and resulted in erroneous conclusions regarding the emission reduction potential of the proposed RMRR rules. Several commenters stated that EPA's IPM analysis incorrectly assumes that no major modifications at any older units would ever trigger the requirement to add new pollution controls. In addition, according to commenters, EPA also erroneously assumed that this lack of major maintenance, repair and replacement will have very little impact on the performance of those power plants, when in reality their emissions would increase significantly. The commenters cited a Clean Air Task Force analysis for power plants, which estimates that EPA's rule revisions will result in at least 7 million more tons of SO_2 and 2.4 million more tons of NO_x annually. Some commenters also questioned the appropriateness of using EPA's analysis for the electric generating sector to draw conclusions about non-utilities.

One commenter said the IPM and DOE NEMS analyses correctly demonstrate that EPA's RMRR proposal will have no appreciable impact on emissions from the power sector. According to the commenter, this conclusion is consistent with EPA's findings in a 1989 report, ''1989 EPA Base Case Forecasts,'' which demonstrated that continuing to allow utilities to undertake activities including ongoing annual operating and maintenance activities and a major refurbishment when the unit reached 30 years of operating life would have no appreciable impact on emissions from the power sector, just as EPA's and DOE's recent analysis confirmed.

One commenter said the proposal lacks any reference to the gains accomplished by major NSR, the ongoing enforcement actions, settlements reached as a result of those actions, or the potential gains from the investigations now pending. The commenter argued that EPA's reliance on improvements in productive capacity as the measure of success fails to consider that productive capacity must be balanced with the interests of health and welfare. The commenter also noted that a critical part of EPA's burden is to consider all the relevant factors leading to its conclusion that the exclusions are necessary and appropriate and that at the very least this includes an assessment of the expected effects on emissions, which in turn will determine the public health benefits and costs of the proposed rule. Although data on emission reductions achieved under the existing program are available, we have stated that we cannot precisely quantify the effects the proposed rule will have on emissions. Some commenters stated that before promulgating a final rule, EPA should provide such a quantitative assessment of the rule.

We disagree with the commenters who believe that emissions would be significantly higher for electric utilities than are estimated under the IPM model runs. These commenters' arguments rely on the assumption that EPA's base case is invalid because, if major NSR rules were left unchanged, eventually all coal-fired utilities would either apply BACT or deteriorate so badly that they would have to shut down. We do not believe this assumption is accurate. As we have explained, our experience suggests that under the current NSR program, managers of coal-fired electric generating facilities have available to them a number of actions they can take to avoid triggering major NSR, and in many instances they will take one of

these actions to avoid the high retrofit costs and delays in obtaining a major NSR permit. If necessary, owners or operators can and will limit their activities to those that do not trigger major NSR, and will take enforceable restrictions on fuel use or other actions to avoid major NSR. This results in some decline in efficiency and capacity, as the EPA's base case modeled, but the units would likely remain viable electric generating units for years without triggering BACT requirements. Thus, we believe our base case represents a far more realistic assessment of what would happen under current major NSR rules than the dramatic BACT reductions presented by these commenters.

Furthermore, while some of the facilities may be modified and subjected to control, nationwide emissions as estimated in the model runs would still rise to the level of the Acid Rain cap for SO_2. To the degree these modifications come at facilities that are otherwise projected to be controlled because of existing SO_2 and NO_X requirements, there would be no difference in effect between the model runs and alternative scenarios. We agree with the commenter who noted that the recent analysis and the estimated impact on emissions is consistent with the previous EPA report in 1989. Our recent analysis confirms that efficiency improvements have the potential to result in environmental benefits that offset (or more than offset) emissions increases from improved availability, but that previous major NSR rules discouraged these improvements.

Regarding the applicability of our analysis to non-utility sectors, we continue to believe that our conclusions are valid for all sectors, and further, that the effects from the electric utility industry dominate those from other sectors. We acknowledge that the results for the SO_2 cap for utilities cannot be extended to non-utilities that are not similarly capped. However, our model runs for NO_x reflected the absence of a cap, and are therefore valid for other uncapped sectors. Thus in the case of industrial boilers, which behave similarly to utilities, we would expect to see similar efficiency improvements and availability improvements occurring in tandem, resulting in either modest increases or decreases. Because the overall emissions from this sector are significantly smaller than for utilities, the modeled effects for utilities are expected to dominate the analysis.

For other industrial sectors, we do not anticipate that emissions increases will result from equipment replacement activities that qualify as RMRR under today's rule. While some efficiency improvements may result, the overall effect of these improvements will not be to induce greater demand and greater emissions, in contrast to the effect shown by the modeling for utilities (*i.e.*, demand for other industrial sectors depends on independent factors). Indeed, without increased demand, efficiency improvements that lower emissions per unit of output would result in a decrease in emissions.

A number of commenters raised concerns that EPA had not analyzed the impact of the final rule on industries other than for electric utilities. We have, thus, supported further efforts to analyze empirically the effects of this rule. This work is included in the Regulatory Impact Analysis (RIA) for the final rule. Even the experts involved in this analysis emphasize that empirical assessments of the costs, emissions, and other economic and environmental effects of this rule are extremely difficult to perform, particularly when generalizing beyond the specific industrial sector and type of facility involved. The analysis would have to simulate a great many decisions made by each plant involving routine maintenance under a variety of policy scenarios. There is simply no credible way to make these assessments for the entire economy or for an entire sector. Hence, with the exception of the electric utility industry model, we relied on a case study approach to gain insights as to how this rule affects particular industrial sectors.

A series of case studies were analyzed by an EPA contractor to estimate the overall impact of the final rule on six different industrial sectors (automobile manufacturing, carbon black manufacturing, natural gas transmission, paper and pulp mills, petroleum refining and pharmaceutical manufacturing). The analysis was designed to examine effects of the final rule, but it is important to note that the case studies were performed prior to decisions on the exact form and content of the final rule. For example, the selection of process units for each of the industries may not be an accurate depiction concerning how a particular industry's operations should be separated into process units under the final rule. As such, none of these characterizations should be taken as EPA's position on appropriate process units for a given industry. (Information on that subject can be found in Section III.F of the preamble and in the final rule for selected industries.) In addition, in costing out replacement activities in the different industries, the contractor made assumptions regarding which costs needed to be included and how multiple replacement activities should be grouped that may not be consistent with the final rule. Again, these assumptions on the part of the contractor should not be interpreted as EPA's conclusions of how their rules should be applied to such replacement activities in these industries.

Even with these caveats, the case studies provide useful insight into the potential effects of the final ERP. The six industries are significant sources of air pollution emissions and are very diverse in terms of their types of operations, their existing maintenance, repair and replacement strategies, and the range of potential replacement costs at some of their process units. This diversity is important because the final rule will impact a great many industrial sectors and individual process units which are extremely varied in terms of their maintenance, repair and replacement strategies. For example, issues related to safety, reliability and availability will vary greatly across these industries. The need to assure that the electricity and natural gas supply is reliable and available is critical to ensuring the safety of the public in the hottest and coldest times of the year, and it is critical to the operation of the nation's infrastructure, to the degree they do not have backup power generation, devoted to public health (*e.g.*, drinking water, sewage treatment, food refrigeration, hospitals). Thus, strategies related to maintenance, repair and replacement at existing facilities are critical to ensure that vital electric utilities and natural gas transmission continue uninterrupted. As we are clarifying what activities fall within the ERP, owners or operators at these facilities will be able to make decisions on when and how to conduct RMRR activities based on engineering judgement.

The case studies conclude that equipment replacement activities vary widely within these industries for the process units selected. Across the industries, the studies estimated that equipment replacement activities could range in percentage by over an order of magnitude. By establishing a threshold at 20 percent of the replacement cost of the process unit, we believe we have set a reasonable standard that allows most replacements to proceed unimpeded as long as the other safeguards are met. At the same time, under the 20 percent threshold, the most capital-intensive replacements would be subject to case-by-case review. The data from these case studies clearly indicate that 20 percent would function well as the dividing line between those replacement activities that automatically qualify under the

ERP and those activities which should be subject to case-by-case review.

The case studies also indicate that replacement activities in these industries should not lead to increased emissions at the sources. Based on the case studies, we believe that replacement with identical or functionally equivalent equipment as the rule requires, will result in equivalent or reduced emissions. The decrease in emissions would result from efficiency improvements that reduce the amount of air pollution emitted per product produced in the process unit. Therefore, if operating levels do not change, then total emissions will decrease with such identical or functionally equivalent equipment replacements.

The case studies looked at a wide range of projects. We have concluded based on this analysis that replacement activities do not generally cause changes in operating levels at the process unit. Instead, other factors, like economic downturns or increased demand for the product of the process unit, will cause operating levels to fluctuate. Efficiency changes, even when they lead to increases in product output from the same raw material input will not lead to increases in emissions unless an independent factor like increased demand for the product also occurs. We strongly support efficiency improvements where they can occur as long as the other safeguards in the rule are met.

Our inability to model economy-wide impacts does not mean we cannot characterize the effects of this rule. In qualitative terms, the case studies further support our conclusion that the old case-by-case approach to RMRR is having perverse effects by discouraging projects that would improve efficiency. As noted elsewhere, efficiency improvements necessarily imply less pollution holding everything else constant. For example, the case study on the pulp and paper industry finds that:

> ''[A]s [safety, reliability and efficiency] activities begin to be reviewed, those that raise * * * questions under the ambiguity of the current rules may be postponed, altered, or simply cancelled. Under the proposed ERP approach, these activities can be tested against a clearer set of criteria, that will allow more activities to be executed.
>
> * * * The new approach provides the regulatory clarity and certainty in making applicability decisions that is completely absent from the current case-by-case approach. Thus, the manner in which mills will handle the processing of equipment replacement activities, with regard to assessing their air permit applicability assessments, will be able to be streamlined. By definition, a ''case-by-case'' approach is simply unworkable for a typical pulp and paper mill, which may have thousands of maintenance and repair related work orders involving equipment replacements executed each year, affecting all areas of mill operations. Clearly, only a small subset of these equipment replacement activities can be evaluated using the complicated and vaguely interpreted multi-factor test inherent with the current case-by-case approach. * * * The proposed ERP approach helps by setting criteria for the routineness determinations. Under the proposed approach, a mill could set up more straight-forward guidelines to be followed throughout an organization that would allow quick and defensible determinations to be made regarding individual maintenance activities.''

Based on the analytical work performed by the contractor for pulp and paper, we expect that, at such facilities, the power boiler would be the most affected by the ERP, as well as an important or even dominant emissions source. We would anticipate that this would be true for many of the inorganic and organic chemical subsectors. In fact, we did not pursue an analysis of the chlor-alkali sector, in large part because the power boiler was the most obvious process unit to analyze, and the issues raised overlapped with the pulp and paper analysis. Thus, it is logical that the conclusions from the case studies would generalize to many other sectors.

Beyond the case studies, there is also a great deal of research and experience that allows for some robust findings. Previous research, such as the articles cited below, supports the following findings:

- *Enhanced efficiency and less pollution in the short run. Holding everything else constant, when a plant's efficiency increases, pollution must go down.* This nation's growing experience with pollution prevention, efficiency enhancements, voluntary environmental programs, and Environmental Management Systems adoption all reinforce the notion that enhanced plant efficiency translates into less environmental pollution.[10] Further, there is an economic incentive to keep plant efficiency high. Proper maintenance and the resulting efficiency enhancements and pollution prevention reduce resource needs and therefore reduce costs.[11] By providing the certainty needed to plan and undertake efficiency investments (economically efficient maintenance) this rule will achieve lower pollution.
- *The rule will allow firms to take advantage of pollution prevention opportunities and new, innovative pollution-reducing technologies.* As technology advances, plants will be able to replace existing components with functionally equivalent components that enhance energy efficiency (and reduce pollution).[12] One example of such an opportunity identified by the EPA contractor in one of the case studies is the replacement of spray guns on a topcoat operation in order to improve the quality of the paint job, while also increasing the transfer efficiency, and decreasing coating and associated solvent usage. This project could be deemed a physical change and have major NSR applicability ramifications if not for the ERP of the RMRR exclusion. Under the current case-by-case approach to RMRR, the facility may forego the change to the newer spray gun design if there is a perceived risk that the determination could be questioned. Under the new ERP approach, the change would proceed more definitively as RMRR, and thus the emission reductions could be realized.
- *While firms can operate existing plants efficiently, the rule preserves powerful incentives within the CAA to adopt ''leap-frog'' technologies and production processes that further reduce costs, increase efficiencies and reduce pollution.* Because of the CAA requirements and economic gains associated with improved efficiency, producers still have an incentive to invest in these clean technologies to replace older facilities.

In addition, a substantial body of research has explored the consequences of environmental regulation that sets more stringent control requirements for new sources. This research explores how differentiated regulation can affect firm behavior both on theoretical and empirical grounds. A listing of some of this literature is included in the RIA for the final rule. This literature provides further evidence that the NSR can easily distort investment and production decisions against more efficient maintenance and replacement.

Therefore, based on the information evaluated, we affirm the overall conclusion of our analysis—that today's rule has no practical effect on the environmental benefits of major NSR in the future. We have presented

[10] By efficiency, we mean unit of input per unit of output, for example, amount of energy needed to produce a specific amount of output. Another example would be the amount of raw material to produce a specific amount of output.

[11] A common example illustrates the point well. When one ''tunes-up'' a car, the automobile gets more miles per gallon, is cleaner burning, and is cheaper to operate.

[12] For example, energy efficiency is not a design parameter to determine functional equivalency for defining routine maintenance. Accordingly, a firm could adopt a more efficient ''functionally equivalent'' technology without fear of triggering NSR provisions.

additional, more detailed supporting information in our final RIA and our response to comments document, both of which can be found in the docket for today's action.

K. Consideration of Other Options

In addition to the cost-based approaches that we proposed, we also asked for comment on age-based and capacity-based approaches, and any other viable option for addressing RMRR.

1. Annual Maintenance, Repair and Replacement Allowance

We are not taking action on the proposed Annual Maintenance, Repair and Replacement Allowance option for the RMRR exclusion, and therefore public comments on this option are not addressed at this time. We will address comments on our proposed Annual Maintenance, Repair and Replacement Allowance if and when we take final action on that proposal.

2. Capacity-Based Option

As mentioned above, we considered the alternative option of developing an RMRR provision based on the capacity of a process unit. Under such an approach, an owner or operator could undertake any activity that does not increase the capacity of the process unit. Basing RMRR on capacity has appeal for several reasons. For starters, an objective of RMRR is to keep a unit operating at capacity and/or availability. In addition, the linkage between capacity and environmental impact is more apparent than that between cost and environmental impact. Finally, this type of approach might, in principle, be easier to use before beginning actual construction than some of the cost-based approaches.

Several commenters were concerned with defining the capacity of a process unit. Capacity may be defined based on input or output. Nameplate capacity of a process unit may vary greatly from the capacity at which the process unit may be able to operate. It may be more appropriate in some industries to measure capacity based on input while in others on output. Commenters felt that a capacity-based approach would not be workable at complex manufacturing sources, because ''capacity'' as a useful shorthand term for the processing capability correlates exactly only with a historical feed or product slate no longer available or made. A number of commenters supported a capacity-based option, generally indicating that a capacity-based option would be simpler and less burdensome to use than the other proposed approaches.

Another large concern of commenters was that a capacity-based approach could prevent facilities from performing activities that make the facilities more efficient. RMRR provisions need to include some form of the other approaches to account for energy efficiency projects at utilities, which could increase output capacity (*i.e.*, production) without necessarily increasing heat input or fuel consumption. Some commenters noted that maximum hourly emissions is a more appropriate surrogate for a change in capacity, because it is consistent with existing NSPS procedures and with averaging periods for ambient air quality monitoring and standards.

We agree that an appropriate capacity-based approach would have to be tailored to various types of sources, with capacity based on input for some and on output for others. As an example, in a review of promulgated and proposed Maximum Achievable Control Technology standards, six of eleven standards measured capacity based on process unit output while five standards based capacity on input. In fact, the NSPS exclusion for increases in production rate at 40 CFR 60.14(e) originally was dependent upon the ''operating design capacity'' of an affected facility. In proposed revisions to the NSPS program published on October 15, 1974, we state (39 *FR* 36948):

> ''The exemption of increases in production rate is no longer dependent upon the ''operating design capacity.'' This term is not easily defined, and for certain industries the ''design capacity'' bears little relationship to the actual operating capacity of the facility.''

We also agree that a capacity-based approach has its limitations, as described by the commenters. We have concluded that the ERP eliminates the need to implement the capacity based approach. We have decided not to finalize a capacity-based approach.

3. Age-Based Option

Under our proposed age-based approach, any process unit under a specified age could undergo any activity that does not increase the capacity of a process unit on a maximum hourly basis without triggering the requirements of the major NSR program. However, the activities could not constitute reconstruction of the process unit; that is, their cost could not exceed 50 percent of the cost of a replacement process unit. The age of the process unit would likely be in the range of 25–50 years. We also proposed that the owner or operator would have to become a Clean Unit as defined at 40 CFR 51.165(c)(3), 51.166(t)(3), and 52.21(x)(3), once the age of a process unit exceeds the age threshold.

Such an approach would provide an owner or operator a clear understanding of RMRR for an extended period of time. It also may provide the owner or operator greater flexibility than under the current system for a limited period of time. Like the capacity-based approach, this approach would, in principle, allow for a fairly simple preconstruction determination of applicability.

Very few commenters expressed any interest in developing this type of approach. Their concerns centered around defining capacity and establishing the age cut-off (because the useful life of equipment is difficult to establish and may vary greatly). Other concerns raised by commenters were that some of the activities that would be allowed at newer sources do not fit within any ordinary meaning of RMRR and some of the activities that would be forbidden at older facilities would come within that meaning, and also that some sources may consciously, and appropriately, engage in aggressive RMRR as a method of maximizing the life span of its process units, and an age-based approach would discriminate against them.

One commenter stated that EPA should establish a normal lifetime, tailored to each industry, beyond which industry would need to install BACT or shut down. This type of approach would obviously require a substantial amount of time and analytical effort.

The age of a source alone is not a legitimate reason to require the addition of pollution control equipment. Age has no direct bearing on a unit's environmental impact; some facilities maintain equipment better than others. We have decided not to promulgate an age-based approach. We have several basic concerns with this approach that we have not been able to reconcile. We also believe that the equipment replacement approach largely addresses the commenters' concerns regarding the age-based approach.

Thus, we have decided not to finalize a rule using this approach.

L. Specific List of Excluded Activities

Several commenters supported the development of lists of activities that are considered RMRR; some of these commenters also supported developing lists of activities that do not qualify as RMRR. Commenters suggested various ways in which such lists could fit into the overall RMRR program. We are concerned, however, that such a list

would have to be implemented through rulemaking, which would require a considerable amount of time, analytical effort, and resources.

A commenter suggested two ways by which we could develop a list of qualifying activities. First, we could review records for ongoing enforcement activity, to identify activities that we have and have not already alleged to be RMRR. There is an ample body of knowledge for electric power plants. Second, we could identify where activities would fall with respect to the cost criteria, then adjust the classification of each activity based on the WEPCO criteria to prepare lists of routine and nonroutine activities.

Some commenters felt that industry-specific lists of routine and nonroutine activities would provide the best interim clarification to major NSR until legislative reform is in place. Other commenters opposed the development of lists of activities that are considered RMRR, contending that such lists would become quickly outdated.

Some commenters requested that certain activities be specifically classified as RMRR. These suggested activities included the following:

- The common practice of changing out the engine core in a combustion turbine when it is due for overhaul (to reduce downtime). The removed engine core is overhauled offline, and is then available to be switched in for the next like-kind engine core that reaches the point of overhaul. Unless the components are upgraded, the heat input remains the same and so does the emissions rate.
- Any change that does not increase the achievable hourly emissions (as determined based on the permit and/or original design parameters) of existing equipment, processes, and emissions units.
- Certain activities, for example, boiler tuning and maintenance, repair and replacement of air pollution equipment or CEMS should be categorically excluded as RMRR.
- Any activity that is part of a long-term service agreement (primarily gas turbines) should be categorically excluded from major NSR.
- Any activity involving steam turbine overhaul work should be categorically excluded from major NSR.

Activities such as the above might be RMRR, but we believe there are simply too many activities in too many industries to effectively improve major NSR implementation through creation of lists. Moreover, lists would be a ''snapshot in time'' that would need to be reviewed and periodically updated for each industry sector. We have consequently decided not to attempt to list activities that are categorically excluded as RMRR.

M. Stand-Alone Exclusion for Energy Efficiency Projects

In the proposal, we acknowledged that certain types of activities that improve energy efficiency would not qualify as RMRR. We solicited comment on whether there was the need for a ''stand-alone'' exclusion for activities that promote energy efficiency.

Many commenters supported a stand-alone exclusion from major NSR for energy efficiency projects. With the following safeguards, they favored specifically excluding from the definition of ''major modification'' activities that promote energy efficiency and/or resource conservation when: (1) The activity results in lower emissions per unit of production or lower energy utilization per unit of production; (2) the percent decrease in emissions or energy utilization per unit of production is greater than the percent increase in maximum hourly emission rates; (3) activity costs do not exceed 50 percent of the replacement value of the process unit; and (4) the activity does not result in an increase in allowable emissions.

Other commenters pointed out that efficiency upgrades will frequently create incentives to further utilize a source and subsequently increase mass emissions. One commenter stated that if activities that result in small efficiency gains can qualify as RMRR, older, dirtier electric generating units will be better able to out-compete newer, much cleaner plants (that have higher costs due to emission controls).

One commenter stated that EPA is incorrect in stating that energy efficiency projects are being discouraged by major NSR, particularly under the new actual-to-projected-actual applicability test. This commenter added that the only projects that are discouraged by major NSR are ones that increase emissions. This commenter felt that the December 2002 final major NSR rules provide a broad range of major NSR exclusions (including revised baseline determinations, Clean Unit designations, pollution control projects, PALS, and combinations of these provisions, as well as an RMRR exclusion) under which energy efficiency projects will certainly occur.

We strongly support efforts to improve energy efficiency at existing power plants. These activities reduce the amount of air pollution emitted per unit of electricity generated. We believe that today's ERP supports energy efficiency projects and that the actual-to-projected-actual applicability test contained in the December 2002 NSR final rules also should remove impediments to energy efficiency projects. Together, these rules will obviate the need for a specified RMRR provision for energy efficiency projects. Thus, at this time we are not finalizing a provision to categorically exclude energy efficiency projects from major NSR.

N. Legal Basis

1. How Does the NSR Program Address Existing Sources and Why Is Today's Rule Consistent With This Approach?

The core of the NSR program is to require preconstruction permits for all new major sources. Congress specifically decided that existing sources generally would not be required to obtain permits. These considerations are the starting point for understanding its application to ''modifications'' and the meaning we should give that term.

The NSR program's scope is closely related to the scope of the NSPS program, created seven years earlier in the CAA Amendments of 1970. In section 111 of the CAA, which sets forth the NSPS provisions, Congress applied the New Source Performance Standards to ''new sources,'' secs. 111(b)(1)(B), 111(b)(4). Congress determined that as a general matter it would not impose the NSPS standards on existing sources, instead leaving to the State and local permitting authorities the decision of the extent to which to regulate those sources through ''State Implementation Plans'' designed to implement National Ambient Air Quality Standards (NAAQS). *See* sec. 110.

Congress followed a similar approach in determining the scope of the major NSR program established by the 1977 Amendments to the CAA. As amended, the CAA specifies that State Implementation Plans must contain provisions that require sources to obtain major NSR permits prior to the point of ''construction'' of a source. Secs. 172(c)(5); 165 (a). By contrast, the CAA generally leaves to State and local permitting authorities in the first instance the question of the extent, means and timetable for obtaining reductions from existing sources needed to comply with National Ambient Air Quality Standards. See secs. 172(c)(1), 161.

NSR's applicability to existing sources to which a ''modification'' is made is an exception to this basic concept. This exception likewise finds its roots in the NSPS program's applicability to ''modifications'' of existing sources. The 1970 CAA made the NSPS program applicable to modifications through its

definition of a ''new source,'' which it defined as ''any stationary source, the construction or modification of which is commenced after the publication of regulations * * * prescribing a[n applicable] standard of performance * * *.'' Section 111(a)(2). Section 111(a)(4), in turn, defined a ''modification'' as ''any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted from such source or which results in the emission of any air pollutant not previously emitted.''

Congress did not further define the terms ''physical change'' or ''change in the method of operation'' in the NSPS program. Therefore we issued regulations to clarify their meaning. As early as our 1971 NSPS regulations, we have made clear that many activities that do not affect the contemplated operation of a unit in a manner consistent with its original design are not physical or operational changes. Specifically, in our 1971 NSPS regulations, we determined that physical or operational changes do not include:

(1) ''Routine maintenance, repair and replacement'' of equipment;

(2) ''An increase in the production rate, if such increase does not exceed the operating design capacity of the affected facility'';

(3) ''An increase in the hours of operation''; and

(4) ''Use of an alternative fuel or raw material if * * * the affected facility is designed to accommodate such alternative use.''

36 FR at 24877 (Dec. 23, 1971). The premise behind characterizing these activities as not being ''changes'' is that they all contemplate that the plant will continue to be operated in a manner consistent with its original design.

The 1977 Amendments to the CAA likewise made the NSR program applicable to ''modifications.'' The original 1977 Amendments did so explicitly only in their provisions dealing with the non-attainment portion of the NSR program, *see* CAA sec. 171(4). But in ''technical and conforming'' amendments to the 1977 Amendments, Congress clarified that it intended the same result with respect to the prevention of significant deterioration provisions, see CAA sec. 169(2)(C).

Notably, Congress did not enact a new definition of ''modification'' in either the original 1977 Amendments or the ''technical and conforming amendments.'' Rather, it incorporated the NSPS definition of ''modification'' by cross-reference. See CAA sec. 169(2)(C); CAA sec. 171(4). In moving the adoption of those amendments, the sponsor (who was also the sponsor of the original 1977 Clean Air Act Amendments and who indicated that the technical amendments had been approved by all members of the original 1977 Amendments conference committee) stated in a summary and statement of intent that he placed in the Congressional Record that this was a deliberate choice. As that summary explained, Congress intended the amendment ''implement[ed] the [1977 Clean Air Act Amendments] conference agreement to cover ''modification'' as well as ''construction'' by defining ''construction'' in part C to conform to usage in other parts of the Act.'' 123 Cong. Rec. 36331 (Nov. 1, 1977). We have understood this to be a reference to our preexisting rules interpreting the term ''modification'' in the NSPS context. 49 FR 43211, 43213 (1984); see also 43 FR 26388, 26394, 26397 (June 19, 1978).

The original 1978 NSR rules concerning modifications that we promulgated after enactment of the 1977 Amendments generally tracked the NSPS approach by specifying that ''routine maintenance, repair and replacement'' was not a change; by specifying that changes in hours of operation and rates of production were not a ''change'; and by using the same basic approach NSPS used to the question of what constitutes an ''increase'' (increase to a source's potential to emit, except that the NSR rule used annual potential to emit while the NSPS program used short-term potential to emit). 43 FR 26388 (June 19, 1978). Even after the D.C. Circuit struck down other portions of our 1978 NSR rules in its original per curiam decision in *Alabama Power Co.* v. *Costle,* 606 F.2d 1068 (D.C. Cir. 1979), we continued to propose to retain the RMRR provision and the ''potential to emit'' approach to emissions increases in our revised rules, although to drop the ''hours of operation and rate of production'' provisions because the ''potential to emit'' provision made them unnecessary. 44 FR 51924, 51937 (September 5, 1979). In our final 1980 NSR rules, however, issued after the D.C. Circuit's final *Alabama Power* decision, 635 F.2d 323 (1980), we changed our approach to the definition of ''increase'' in the NSR context to specify that a change would trigger NSR if it would result in an increase over ''actual annual emissions.'' 45 FR 52676 (August 7, 1980). At the same time, and notably, we restored the provisions stating that increases in hours of operation or production rate were not ''changes.'' *Id.* at 52704.

It is important to understand what we did—and did not—decide in those final 1980 NSR rules. What we did decide was that as a general proposition, we would better serve the purposes of the NSR program if we used ''actual'' rather than ''potential'' emissions as a baseline for determining whether an activity at a new source results in an emissions increase. What we did not decide was that the purposes of the NSR program never allow us to exclude from the definition of ''change'' any activity at a plant that may increase its actual emissions but does not increase its ''potential'' emissions. In particular, for example, we decided to retain the ''hours of operation'' and ''rate of production'' exclusions even though such changes might result in increases in ''actual'' emissions because not having the provisions ''would severely and unduly hamper the ability of any company to take advantage of favorable market conditions.'' *Id.* Similarly, we retained the exclusion for ''routine maintenance, repair and replacement'' even though it too can result in emission increases. Yet there is little doubt that increases in hours of operation and rates of production and RMRR arguably could be understood to fall within the statutory definition of modification, since increases in hours of operation and rates of production certainly may be argued to be changes in the ''method of operation'' of a plant, and RMRR certainly may be argued to be a ''physical change'' to a plant. On balance, however, we rejected that interpretation and determined that the definition of modification should not be read so broadly as to encompass hours of operation or production rate increases, at least so long as they are unrelated to a physical change.

In the revisions to the NSR program we announced last December, we reiterated our adherence to the view that as a general matter we should continue to use ''actual'' rather than ''potential'' emissions in determining what activities constitute ''modifications'' under NSR. We continue to believe that is correct, but we also believe we should amplify our reasons for holding this view and why that view is entirely consistent with the rule we are promulgating today. In determining the scope to give to ''modification,'' we believe it is important to give weight to both aspects of what Congress decided in 1977. Congress decided that generally speaking, existing plants would not be subject to NSR, but that they would be subject to NSR when they made

''modifications.'' It is also important to understand why Congress chose this point at which to impose NSR on existing plants: to avoid the need to impose costly retrofits, but require placement of new control technology at a time when it makes the most sense for it to be installed. *See* H.R. Rep. No. 294, 95th Cong., 1st Sess. 185, *reprinted in* 1977 U.S. Code Cong. & Admin. News at 1254; 116 Cong. Rec. 32,918 (Sept. 21, 1970) (remarks of Sen. Cooper). *See also WEPCO,* 893 F.2d at 909–910; *National-Southwire Aluminum Co.* v. *EPA,* 838 F.2d 835, 843 (6th Cir., Boggs, J., dissenting), *cert. denied,* 488 U.S. 955 (1988). A wholesale exclusion of any activity that restores a plant to its potential to emit from the definition of modification is not consistent with this balance, since there are many activities that might have that effect but the conduct of which would be an extremely effective time for the placement for new control technology.

At the same time, we believe it is also important to give equal weight to the converse proposition that existing plants should not have to install new control technology in the ordinary course of their operations. To require them to do so would fail to give full effect to Congress's decision that existing sources generally would not be required to obtain permits. It would also subject these plants and the consumers who rely on them to enormous dislocation and expense. That is why we believe we have rightly excluded increases in hours of operation and rates of production from the definition of ''change.'' That is also why we believe we have rightly excluded ''routine maintenance, repair and replacement'' of existing plants from that definition.

For similar reasons, we believe today's rule draws an appropriate line of demarcation between replacements that should not be treated as changes, and those as to which further consideration of the question is appropriate. Our rule states categorically that the replacement of components with identical or functionally equivalent components that do not exceed 20% of the replacement value of the process unit and does not change its basic design parameters is not a change and is within the RMRR exclusion. On the other hand, the rule contemplates case-by-case evaluation of identical or functionally equivalent equipment replacements that do not have these characteristics.

We believe this approach is consistent with the intended scope of ''modification'' under the NSR program. The record of this rulemaking demonstrates that there are substantial categories of replacement activities undertaken in order to assure the safety, reliability and efficiency of existing plants that, if conducted at the same time, cost less than the 20-percent replacement cost threshold. It also demonstrates that there are sound business reasons why an owner or operator may find it makes sense to conduct some of these activities at the same time.

On the other hand, given the costs and technical problems associated with installing state-of-the-art pollution controls at existing facilities, we do not believe it plausible that, if faced with the choice of replacing equipment that has a value less than 20 percent of a process unit and having to install those controls, or coming up with another solution—such as repairing the existing equipment or limiting hours of operation so as to be confident that the activity will not trigger NSR—the owner of a source would elect to replace the equipment if he also has to install the state-of-the-art controls. Rather, we believe he will repair the existing equipment or artificially constrain production. Therefore the replacement of that equipment is not, in fact, an opportune time for the installation of such controls. It follows that treating such replacements as an NSR trigger will not lead to the installation of controls. Rather, it will merely create incentives to make a plant less productive than its design capacity would allow it to be.

We do not believe it is the policy of the CAA to seek to promote emissions reductions by forcing new limits on hours of operation or rates of production of existing plants. We made that point clear in 1980 when we determined that we should retain the hours of operation and rate of production exclusions in the NSR context. To the contrary, as we said in promulgating the 1980 rules, Congress's decision to exclude existing sources because of the dislocation that covering them would cause can reasonably be understood as allowing those sources to increase hours of operation or production up to permitted levels as market conditions dictate. We note that this does not leave such activities outside the scope of the CAA: if a State concludes that resulting air quality considerations warrant revision to its SIP to add further limitations to a permit, it may exercise its authority to impose them, even in the absence of anything that constitutes a ''change'' to an existing plant. But we believe that our 1980 conclusion that increases in hours of operation or production at existing plants should not trigger NSR remains the better construction of the CAA. That being the case, we now believe that the fact that such increases may occur after replacement of equipment that does not present an opportune time for the installation of controls should change that conclusion.

To summarize: with respect to existing sources, the purpose of the NSR provisions is simply to require the installation of controls at the appropriate and opportune time. The kind of replacements that automatically fall within the equipment replacement provision established today do not represent such an appropriate and opportune time. Accordingly, and given that it is consistent with the meaning of ''change'' to treat this kind of replacement as not being a ''change,'' we believe excluding them on that basis from the definition of ''modification'' as used in the NSR program is well calculated to serve all of the policies of the NSR provisions of the CAA, and is therefore a legitimate exercise of our discretion under *Chevron, U.S.A. Inc.* v. *NRDC,* 467 U.S. 837 (1984), to construe an ambiguous term. Likewise, we believe this approach is consistent with the holding in the *WEPCO* case, and with some though not all of that case's reasoning.

Today's rule treats the activities excluded from the definition of ''change'' as a category of ''routine maintenance, repair and replacement''. We received many comments as to whether we can and should adopt the ERP as an expansion of the RMRR exclusion. We believe it is appropriate to expand the former RMRR exception. Before promulgation of today's rule, we interpreted the phrase ''routine maintenance, repair and replacement'' to be limited to the day-to-day maintenance and repair of equipment and the replacement of relatively small parts of a plant that frequently require replacement. Today we are expanding the former definition of RMRR through this rulemaking to include other activities covered by the 20 percent cost threshold that are needed to facilitate the efficiency, reliability and safety of affected sources.

We believe it is appropriate to add one final note regarding the fact that this approach represents a change from the approach we have taken in the recent past. As the Supreme Court explained in *Chevron,* where it upheld a considerably more significant shift in the Agency's understanding of Title I of the CAA, to wit, the scope of the term ''stationary source,'' there is nothing inherently suspect about a change of approach of this type by an expert Agency seeking to interpret a technical statutory term so as best to accommodate competing

interests that Congress has charged the Agency with reconciling.

In section 101 of the CAA, Congress stated that Title I of the CAA has a dual purpose: ''to protect and enhance the quality of the Nation's air resources *so as to promote the public health and welfare and the productive capacity of its population*'' (emphasis added). This duality is reiterated in the statement of purpose of the PSD provisions and in the House Report accompanying the 1977 Amendments in connection with the non-attainment provisions. See sec. 160(1) (purposes of the PSD program are, inter alia, ''to protect public health and welfare from any actual or potential adverse effect'' of air pollution and ''to insure that economic growth will continue to occur consistent with the preservation of existing clean air resources''); H.R. Rep. No. 95–294, p. 211 (The ''two main purposes'' of the non-attainment permitting program are ''(1) to allow reasonable economic growth to continue in an area while making reasonable further progress to assure attainment of the standards by a fixed date; and (2) to allow States greater flexibility for the former purpose than EPA's present interpretative regulations afford'').

More specifically, with regard to the question at issue here, Congress directed EPA not to apply NSR preconstruction permitting requirements to existing plants as a general matter, but to apply them to ''modifications.'' Both directives are entitled to receive appropriate weight.

In these circumstances, changes in an Agency's understanding informed by greater experience are not only not surprising, they are to be expected. Effectuating these underlying Congressional commands requires a careful weighing and accommodation of the competing considerations underlying them. Sensitivity to unintended consequences, and a willingness to adjust policies in a manner informed by a better understanding of those consequences, are a central element of the responsibilities of an Agency given such a charge. As the *Chevron* Court explained:

> Our review of the EPA's varying interpretations of the word ''source''—both before and after the 1977 Amendments—convinces us that the agency primarily responsible for administering this important legislation has consistently interpreted it flexibly—not in a sterile textual vacuum, but in the context of implementing policy decisions in a technical and complex arena. The fact that the agency has from time to time changed its interpretation of the term ''source'' does not, as respondents argue, lead us to conclude that no deference should be accorded the agency's interpretation of the statute. An initial agency interpretation is not instantly carved in stone. On the contrary, the agency, to engage in informed rulemaking, must consider varying interpretations and the wisdom of its policy on a continuing basis. Moreover, the fact that the agency has adopted different definitions in different contexts adds force to the argument that the definition itself is flexible, particularly since Congress has never indicated any disapproval of a flexible reading of the statute.

467 U.S. at 863–64.

The Court went on to point out:

> In these cases the Administrator's interpretation represents a reasonable accommodation of manifestly competing interests and is entitled to deference: the regulatory scheme is technical and complex, the agency considered the matter in a detailed and reasoned fashion, and the decision involves reconciling conflicting policies. Congress intended to accommodate both interests, but did not do so itself on the level of specificity presented by these cases. * * *
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> [A]n agency to which Congress has delegated policymaking responsibilities may, within the limits of that delegation, properly rely upon the incumbent administration's views of wise policy to inform its judgments. While agencies are not directly accountable to the people, the Chief Executive is, and it is entirely appropriate for this political branch of the Government to make such policy choices—resolving the competing interests which Congress itself either inadvertently did not resolve, or intentionally left to be resolved by the agency charged with the administration of the statute in light of everyday realities. * * *
>
> We hold that the EPA's definition of the term ''source'' is a permissible construction of the statute which seeks to accommodate progress in reducing air pollution with economic growth. 'The Regulations which the Administrator has adopted provide what the agency could allowably view as * * * [an] effective reconciliation of these twofold ends. * * *'

Id. at 865–66 (citations and footnotes omitted). We believe the same reasoning applies here, and makes it entirely appropriate for us to adopt the equipment replacement provision today.

2. Why Today's Rule Appropriately Implements the Clean Air Act's Definition of Modification

As noted above, the modification provisions of the NSR program in parts C and D of title I of the CAA are based on the definition of modification in section 111(a)(4) of the CAA. The term ''modification'' means ''any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' As we observed in the notice of proposed rulemaking for this rule, that definition contemplates that you will first determine whether a physical or operational change will occur. If so, then you proceed to determine whether the physical or operational change will result in an emissions increase over baseline levels.

Real-world, common-sense usage of the word ''change'' in ''physical change'' and ''change in the method of operation'' shows that ''change'' is susceptible to multiple meanings. As we have noted previously, ''EPA has always recognized that Congress did not intend that every activity at an existing facility be considered a physical or operational change for purposes of NSR.'' 57 FR 32,314, 32,319 (July 21, 1992). Conceivably, ''change'' could encompass a range of activities from periodically replacing filters in production machinery, to once in-a-lifetime anticipated replacement of a component, to complete replacement of a production unit.

For example, all cars must periodically have their oil ''changed.'' When considered from one perspective, this activity does represent a ''change'' because old oil is removed and new oil is added. From another perspective, however, this activity would not be considered a change because it does not alter any significant characteristic of the car.

More to the point, chemical and pharmaceutical manufacturing operations often are designed, operated, and permitted as ''multi-function'' facilities. These facilities have numerous pieces of equipment (such as storage tanks, reactors, distillation columns, centrifuges, filter dryers, *etc.*) that can be reconfigured to accommodate a wide variety of products and operating conditions. When switching from product X to product Y, a plant can make substantial ''changes'' in the types of equipment used, the processing conditions, and the raw materials, reagents, solvents, and other processing materials. In this case, the same basic equipment is used to make a wide variety of end products. But, as long as the facility is operated as designed and permitted, we would not consider (and have not considered over the 20+ year life of the NSR program) such changes to be physical or operational ''changes'' for purposes of administering the NSR program.

Similarly, manufacturing equipment often is built with expendable components. For example, industrial gas turbines, such as those used to drive compressors on natural gas pipelines, regularly need to have components

replaced as they wear out due to the high temperature and pressure conditions inside the turbine. In fact, these gas turbines are built with the knowledge and expectation that such replacements will be needed. In recognition of this fact, under the New Source Performance Standard for gas turbines, 40 CFR part 60, subpart GG, we have concluded that ''replacement of stator blades, turbine nozzles, turbine buckets, fuel nozzles, combustion chambers, seals, and shaft packings' are not ''changes'' for regulatory purposes. See EPA–450/2–77–017a, background support document for Subpart GG. Such replacements are akin to getting a new set of brakes on a car—not something that happens often, not an activity that is necessarily inexpensive, but plainly an activity that is an expected part of maintaining and operating the facility and one that does not represent an alteration of the affected process unit.

As the preceding examples suggest, identifying activities that are ''changes'' for NSR purposes—and thus potentially trigger the need for an NSR permit—requires the exercise of Agency expertise. The application of agency expertise to the interpretation of this statutory term is the classic situation in which an agency is accorded deference under *Chevron, U.S.A., Inc.* v. *NRDC,* 467 U.S. 837 (1984).

Historically, we have asserted the power to interpret the relevant statutory terms. For example, even though both the NSPS and NSR programs incorporate the definition of ''modification'' from section 111, from the outset EPA has adopted quite disparate readings of the term in our rules. *See* 57 FR 32314, 32316 (July 21, 1992) (WEPCO rule discussion of how emission increases are calculated differently for the NSPS and NSR programs). The NSPS program requires a change to result in an increase in the hourly potential to emit of the facility. 40 CFR 60.14(a)–(b). In contrast, under NSR, we require an increase in annual emissions. *E.g.,* 40 CFR 51.165(a)(1)(x). These disparate tests reflect the Agency's view that the statutory term ''modification'' must be construed with a view to what makes sense in particular statutory context, and are not obvious on their face.

The exclusions from NSR we adopted in 1980 also reflect the exercise of the *Chevron* discretion. Not only did we adopt the RMRR exclusion at that time, but we also adopted exclusions for increases in the hours of operation, fuel changes, and raw material changes. Only the RMRR exclusion arguably could be justified as *de minimis*. For example, by doubling hours of operation, a 500 tpy emitting plant could conceivably double its emissions.[13] The extra 500 tpy is far above any level EPA has ever thought justifiable as *de minimis. E.g.,* 40 CFR 51.166(b)(23)(i) (definition of ''significant''). Nor is it likely that these other exclusions could be based on some inherent power to adopt categorical exclusions from the CAA's commands. *See Alabama Power Company* v. *Costle,* 636 F.2d 323, 359 (D.C. Cir. 1980) (''categorical exemptions * * * are not favored''). Accordingly, these other exclusions must be justified as an exercise of *Chevron* discretion.

As noted previously, in 1977 when Congress incorporated by reference into the NSR program the pre-existing NSPS statutory definition of modification, EPA had already adopted and had been administering regulations and policy under the NSPS program related to the meaning of the term ''modification.'' Our rules and policy provided that certain significant activities did not constitute physical or operational changes under the NSPS program prior to 1977 (or, for that matter, under the NSPS program as administered today). In addition to the gas turbine example provided above, perhaps the best indication that EPA did not consider the terms ''modification'' or ''change'' to cover everything other than *de minimis* activities is the exclusion for production rate increases under the NSPS program. 40 CFR 60.14(e)(2).

Under this provision, projects valued at millions of dollars can be implemented—with no limitations on the nature of the project—without triggering applicable NSPSs. For example, up to 10 percent of the asset value of affected operations at a kraft pulp mill can be invested in a project without triggering the applicable NSPS, 40 CFR part 60, subpart BB. The affected facilities at a kraft pulp mill typically are valued in excess of $100 million. Therefore, an owner or operator can implement projects costing millions of dollars without triggering the applicable NSPS. This holds true regardless of the nature of the project—it can be a ''like-kind'' replacement of the kind addressed by today's rule or it can result in a substantial change in the nature of the operation. Thus, under the NSPS program that existed when Congress enacted NSR and incorporated into NSR the applicable NSPS definitions, projects of substantial cost that result in substantial change in affected facilities were not considered ''changes.'' The same is true under the NSPS program as it stands today.

We recognize that the Agency previously has not specifically asserted that our interpretation of ''change'' and the exclusions from NSR are based on an exercise of *Chevron* discretion. In some instances, such as in a decision of the EAB, *In re: Tennessee Valley Authority,* 9 E.A.D. 357 (EAB 2000), and in briefs in various enforcement-related cases, we have previously interpreted ''change'' such that virtually all changes, even trivial ones, are encompassed by the CAA. Thus, we generally interpreted the exclusion as being limited to *de minimis* circumstances. However, EPA does have the authority to interpret these key terms through rulemaking. Upon further consideration of the history of our actions, the statute, and its legislative history, EPA believes that a different view is permissible, and, for policy reasons discussed above, more appropriate. Therefore, we adopt this view prospectively in today's action.[14]

The argument that our authority to exclude certain activities from being modifications under new source review can only be based on a *de minimis* rationale sometimes relies on the word ''any'' used to modify ''physical change'' and ''change in the method of operation,'' pointing to the word ''any'' in the definition of ''modification'' as a signal from Congress that the term ''change'' must be interpreted as encompassing the broadest possible sense of the term. Such an interpretation is not compelled by the language and legislative history of the statute, as demonstrated by the manner in which we have interpreted the word ''change'' under both the NSPS and the NSR programs.[15]

[13] As discussed below, our regulations provided a comparable exclusion from NSPS at the time of the 1977 Amendments that established the NSR program.

[14] We have taken positions in numerous court filings concerning the proper interpretation and usage of key statutory terms, such as ''physical change'' and ''any physical change.'' These positions were based on permissible constructions of the statute of which the regulated community had fair notice, and correctly reflect the Agency's reasonable accommodation of the Clean Air Act's competing policies in light of its experience at the time it adopted the RMRR exclusion in 1980. The Agency has sought, and has obtained, deference for its interpretations, and, notwithstanding today's adoption of a revised interpretation of the statute and an expansion of the RMRR exclusion, the Agency shall continue to seek deference for those prior interpretations in ongoing enforcement litigation.

[15] We note that the word ''any'' is simply a modifier that does not change the meaning of the word it modifies. For example, using the term ''any'' to modify the word ''car'' does not somehow change or expand the meaning of the word ''car.'' ''Any'' simply means that, once you have decided what a car is, then all objects meeting the definition are encompassed.

Nothing in the appellate case law directly disposes of this issue in a manner that prevents a new interpretation today. Two cases, *Alabama Power* and *WEPCO,* are relied on by some commenters to assert that EPA must interpret ''modification'' and ''change'' expansively and base all exclusions on a *de minimis* rationale. However, in *Alabama Power,* the issue before the court was the emissions increase portion of the definition of ''modification.'' The court would have allowed *de minimis* increases in emissions to be excluded from requirements applying to ''modifications'' under new source review but not emissions increases equal to the thresholds set by statute for new construction. 636 F.2d at 399–400. The court did not have before it the issue of what is a ''change'' and did not decide this issue.

In *WEPCO,* both parties advanced the view that the statute was clear on its face. EPA advanced the view that the term ''modification'' is necessarily broad, and that only *de minimis* departures are appropriate. WEPCO asserted that the plain meaning of the term ''physical change'' allowed for the five large scale rehabilitation projects it contemplated at its Port Washington plant. The *WEPCO* court held that the rehabilitation projects at issue were too large to reasonably conclude that they should not be treated as physical changes. The court's holding that the statute did not require the interpretation advanced by *WEPCO* does not deny EPA the discretion to decide to adopt a different, reasonable interpretation of the term ''modification.''

While the Court in WEPCO decided that the projects in that case were physical changes, the decision in *WEPCO* does not answer the question of where to draw the line between activities that should and should not be considered ''changes.'' Nevertheless, contrary to the suggestions of several commenters, the projects at issue in *WEPCO* would have cost more than the 20 percent of replacement cost threshold selected today and, barring other applicable exclusions, would have been subject to case-by-case review in the PSD program. *See* section III.D above.[16]

Some commenters argued that, to further the purposes of the statute, any interpretation must result in the eventual elimination of so-called ''grandfathered'' facilities. We recognize the need to reduce emissions from many existing plants—regardless of whether they are ''grandfathered'' (because they have never gone through NSR) or whether they have previously gone through NSR but can further reduce their emissions. EPA and States have issued regulations under a variety of statutory provisions to accomplish this goal in the past, and we will continue to do so in the future. We do not believe, however, the modification provisions of the CAA should be interpreted to ensure that all major facilities eventually trigger NSR. In fact, such an interpretation cannot be squared with the plain language of the CAA.

An existing source—whether grandfathered or not—triggers NSR only if it makes a physical or operational change that results in an emissions increase. Thus, a facility can conceivably continue to operate indefinitely without triggering NSR—making as many physical or operational changes as it desires—as long as the changes do not result in emissions increases. This outcome is an unavoidable consequence of the plain statutory language and is at odds with the notion that Congress intended that every major source would eventually trigger NSR. Moreover, there is nothing in the legislative history of the 1977 Amendments, which created the NSR program, to suggest that Congress intended to force all then-existing sources to go through NSR. To the extent that some members of Congress expressed that view during the debate over the 1990 amendments, such statements are not probative of what Congress meant in 1977. *Central Bank of Denver, N.A.* v. *First Interstate Bank of Denver, N.A.,* 511 U.S. 164, 185–86 (1994), and cases cited.

In deciding to incorporate by reference the statutory definition of ''modification'' in section 111, Congress's intent cannot have been to preclude us from adopting an interpretation of ''modification'' or ''change'' that differs from one that sweeps in all activities at a source. Under the NSPS program, this interpretation did not apply at the time of the 1977 amendments. When the NSPS definition of ''modification'' was adopted as part of the NSR program in 1977, the *Congressional Record* explained that this provision, ''[i]mplements conference agreement to cover ''modification'' as well as ''construction'' by defining ''construction'' in part C to *conform to usage in other parts of the Act.*'' 123 Cong. Rec. 36331 (Nov. 1, 1977) (emphasis added). Although we do not assert that the NSPS interpretation is the only one we could have adopted for NSR purposes (we followed quite a different interpretation from 1980 until today) at the very least it delineates a zone of discretion within which EPA may operate.

Our interpretation today of physical or operational change in a flexible way furthers the purposes of the statute. As noted above, Congress made it clear that the CAA in general, and the NSR program in particular, should be administered in a manner that protects the environment and promotes the productive capacity of the nation. CAA section 101(b)(1). The *Chevron* Court recognized Congress' intent and noted that ''Congress sought to accommodate the conflict between the economic interest in permitting capital improvements to continue and the environmental interest in improving air quality'' when it established the NSR program. *Chevron,* 467 U.S. at 851. Generally, we believe that these goals are best accomplished by providing state and local governments with discretion to make decisions as to what emissions reductions are needed in their jurisdictions to attain and maintain good air quality. *See* CAA section 101(a)(3).

It is now clear that many power plants and industrial facilities must substantially reduce their emissions in order to allow States to meet the stringent Federal air quality standards that the Supreme Court upheld in 2002. Under the CAA, Congress designed a number of regulatory programs that will collectively achieve the necessary reductions. Although the NSR program will effectively limit emissions from new and modified sources, it was not designed to achieve emission reductions from every existing source.

[16] We note that decisions recently were rendered in two of the Agency's pending NSR enforcement cases in the utility sector. In both cases, the Agency asserted that the then existing RMRR exclusion should be applied in a narrow fashion such that only *de minimis* projects should be excluded under that rule. In our case against Ohio Edison in the U.S. District Court for the Southern District of Ohio, the court determined that the disputed projects did not qualify for the existing RMRR exclusion. The Agency sought and received from the court broad deference with regard to the Agency's interpretation of the CAA and the relevant EPA rules. In our case against Duke Energy in the U.S. District Court for the Middle District of North Carolina, the court issued a decision on cross motions for summary judgment. The decision took exception with several legal conclusions reached in the Ohio Edison decision and determined that the then existing RMRR exclusion must be applied from the perspective of what projects are routine within the relevant industrial source category. EPA today is adopting prospectively a new interpretation of the CAA and is finalizing a revision to the RMRR regulation at issue in those cases.

IV. Administrative Requirements for This Rule

A. Executive Order 12866—Regulatory Planning and Review

Under Executive Order 12866 [58 FR 51735 (October 4, 1993)], we must determine whether the regulatory action is ''significant'' and therefore subject to review by the Office of Management and Budget (OMB) and the requirements of the Executive Order. The Executive Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, OMB has notified us that it considers this an ''economically significant regulatory action'' within the meaning of the Executive Order. We have submitted this action to OMB for review. Changes made in response to OMB suggestions or recommendations will be documented in the public record. All written comments from OMB to EPA and any written EPA response to any of those comments are included in the docket listed at the beginning of this notice under **ADDRESSES**. In addition, consistent with Executive Order 12866, we consulted with the State, local and tribal agencies that will be affected by this rule. We have also sought involvement from industry and public interest groups.

B. Executive Order 13132—Federalism

Executive Order 13132, entitled ''Federalism'' (64 *FR* 43255, August 10, 1999), requires us to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' are defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not have federalism implications. Nevertheless, as described in section II.C of this notice, in developing this rule, we consulted with affected parties and interested stakeholders, including State and local authorities, to enable them to provide timely input in the development of this rule. This rule will not have substantial direct effects on the States, on the relationship between the national government and the State and local programs, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. We expect this rule will result in some expenditures by the States, we expect those expenditures to be limited to $580,000 for the estimated 112 affected reviewing authorities. This estimate reflects the small increase in burden imposed upon reviewing authorities in order for them to revise their State Implementation Plans (SIP). However, this revision provides sources permitted by the States greater certainty in application of the program, which should in turn reduce the overall burden of the program on State and local authorities. Thus, the requirements of Executive Order 13132 do not apply to this rule.

C. Executive Order 13175—Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 *FR* 67249, November 6, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' We believe that this rule does not have tribal implications as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply.

The purpose of today's final rule is to add greater flexibility to the existing major NSR regulations. These changes will benefit reviewing authorities and the regulated community, including any major source owned by a tribal government or located in or near tribal land, by providing increased certainty as to when the requirements of the major NSR program apply. Taken as a whole, today's rule should result in no added burden or compliance costs and should not substantially change the level of environmental performance achieved under the previous rules and guidance.

We anticipate that initially these changes will result in a small increase in the burden imposed upon reviewing authorities in order for them to be included in the State's SIP. Nevertheless, these options and revisions will ultimately provide greater operational flexibility to sources permitted by the States, which will in turn reduce the overall burden on the program on State and local authorities by reducing the number of required permit modifications. In comparison, no tribal government currently has an approved Tribal Implementation Plan (TIP) under the CAA to implement the NSR program. The Federal government is currently the NSR reviewing authority in Indian country. Thus, tribal governments should not experience added burden, nor should their laws be affected with respect to implementation of this rule. Additionally, although major stationary sources affected by today's rule could be located in or near Indian country and/or be owned or operated by tribal governments, such affected sources would not incur additional costs or compliance burdens as a result of this rule. Instead, the only effect on such sources should be the benefit of the added certainty and flexibility provided by the rule.

We recognize the importance of including tribal outreach as part of the rulemaking process. In addition to affording tribes an opportunity to comment on this rule through the proposal, on which two tribes did submit comments, we have also alerted tribes of this action through our website and quarterly newsletter. To this point we have not specifically consulted with tribal officials on this rule, but we are committed to work with any tribal government to resolve any issues that we may have overlooked in today's rules and that may have an adverse impact in Indian country.

D. Executive Order 13045—Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045, ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 *FR* 19885, April 23, 1997) applies to any rule that (1) is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, we must evaluate the environmental health or safety effects of the planned rule on children and explain why the planned regulation is preferable to other

potentially effective and reasonable alternatives that we considered.

This rule is not subject to Executive Order 13045, because we do not have reason to believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. We believe that, based on our analysis of electric utilities, this rule as a whole will result in equal or better environmental protection than currently provided by the existing regulations, and do so in a more streamlined and effective manner.

E. Paperwork Reduction Act

The information collection requirements in this final rule have been submitted for approval to OMB under the requirements of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* An ICR document has been prepared by EPA (ICR No. 1230.14), and a copy may be obtained from Susan Auby, U.S. Environmental Protection Agency, Office of Environmental Information, Collection Strategies Division (2822T), 1200 Pennsylvania Avenue, NW., Washington, DC 20460–0001, by e-mail at auby.susan@epa.gov, or by calling (202) 566–1672. A copy may also be downloaded off the Internet at *http://www.epa.gov/icr.* The information requirements included in ICR No. 1230.14 are not enforceable until OMB approves them.

The information that ICR No. 1230.14 covers is required for the submittal of a complete permit application for the construction or modification of all major new stationary sources of pollutants in attainment and nonattainment areas, as well as for applicable minor stationary sources of pollutants. This information collection is necessary for the proper performance of EPA's functions, has practical utility, and is not unnecessarily duplicative of information we otherwise can reasonably access. We have reduced, to the extent practicable and appropriate, the burden on persons providing the information to or for EPA. In fact, we feel that this rule will result in less burden on industry and reviewing authorities since it streamlines the process of determining whether a replacement activity is RMRR.

However, according to ICR No. 1230.14, we do anticipate an initial increase in burden for reviewing authorities as a result of the rule changes, to account for revising state implementation plans to incorporate these rule changes. As discussed above, we expect those one-time expenditures to be limited to $580,000 for the estimated 112 affected reviewing authorities. For the number of respondent reviewing authorities, the analysis uses the 112 reviewing authorities count used by other permitting ICR's for the one-time tasks (for example, SIP revisions).

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purpose of responding to the information collection; adjust existing ways to comply with any previously applicable instructions and requirements; train personnel to respond to a collection of information; search existing data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15. We will continue to present OMB control numbers in a consolidated table format to be codified in 40 CFR part 9 of the Agency's regulations, and in each CFR volume containing EPA regulations. The table lists the section numbers with reporting and recordkeeping requirements, and the current OMB control numbers. This listing of the OMB control numbers and their subsequent codification in the CFR satisfy the requirements of the *Paperwork Reduction Act* (44 U.S.C. 3501 *et seq.*) and OMB's implementing regulations at 5 CFR part 1320.

F. Regulatory Flexibility Analysis

We determined it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule. We have also determined that this rule will not have a significant economic impact on a substantial number of small entities. For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) Any small business employing fewer than 500 employees; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant adverse economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives ''which minimize any significant economic impact of this rule on small entities.'' 5 U.S.C. Sections 603 and 604. Thus, an agency may conclude that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect on all of the small entities subject to the rule. Today's rule will not have a significant economic impact on a substantial number of small entities because it will decrease the regulatory burden of the existing regulations and have a positive effect on all small entities subject to the rule. This rule improves operational flexibility for owners or operators of major stationary sources and clarifies applicable requirements for determining if a change qualifies as a major modification. We have therefore concluded that today's rule will relieve regulatory burden for all small entities.

G. Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of UMRA, we generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows us to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted.

Before we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of our regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We believe these rule changes will actually reduce the regulatory burden associated with the major NSR program by improving the operational flexibility of owners or operators and clarifying the requirements. Because the program changes provided in the rule are not expected to result in a significant increase in the expenditure by State, local, and tribal governments, or the private sector, we have not prepared a budgetary impact statement or specifically addressed the selection of the least costly, most cost-effective, or least burdensome alternative. Because small governments will not be significantly or uniquely affected by this rule, we are not required to develop a plan with regard to small governments. Therefore, this rule is not subject to the requirements of section 203 of the UMRA.

H. National Technology Transfer and Advancement Act of 1995

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104–113, section 12(d) (15 U.S.C. 272 *note*) directs us to use voluntary consensus standards (VCS) in our regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (for example, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs us to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

Although this rule does involve the use of technical standards, it does not preclude the State, local, and tribal reviewing agencies from using VCS. Today's rule is an improvement of the existing NSR permitting program. As such, it only ensures that promulgated technical standards are considered and appropriate controls are installed, prior to the construction of major sources of air emissions. Therefore, we are not considering the use of any VCS in today's rule.

I. Executive Order 13211—Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This rule is not a ''significant energy action'' as defined in Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution or use of energy.

Today's rule improves the ability of sources to maintain the reliability of production facilities, and effectively utilize and improve existing capacity.

J. Executive Order 12988—Civil Justice Reform

This final rule does not have any preemptive or retroactive effect. This action meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden.

V. Effective Date for Today's Requirements

All of these changes will take effect in the Federal PSD program (codified at § 52.21) on December 26, 2003. This means that these rules will apply on December 26, 2003, in any area without an approved PSD program, for which we are the reviewing authority, or for which we have delegated our authority to issue permits to a State or local reviewing authority.

To be approvable under the SIP, State and local agency programs implementing part C (PSD permit program in § 51.166) or part D (nonattainment NSR permit program in § 51.165) must include today's changes as minimum program elements. State and local agencies should assure that any program changes under §§ 51.165 and 51.166 are consistently accounted for in other SIP planning measures. State and local agencies must adopt and submit revisions to their part 51 permitting programs implementing these minimum program elements no later than October 27, 2006. That is, for both nonattainment and attainment areas, the SIP revisions must be adopted and submitted within 3 years from today. The CAA does not specify a date for submission of SIPs when we revise the PSD and NSR rules. We believe it is appropriate to establish a date analogous to the date for submission of new SIPs when a NAAQS is promulgated or revised. Under section 110(a)(1) of the CAA, as amended in 1990, that date is 3 years from promulgation or revision of the NAAQS. Accordingly, we have established 3 years from today's revisions as the required date for submission of conforming SIP revisions.

Today's rule revises the Federal PSD program located at 40 CFR 52.21 to include the new equipment replacement provision of the RMRR exclusion. The part 52 regulations governing Federal permitting programs include the Federal PSD rule at 40 CFR 52.21 as well as the various sections of subparts C through DDD of part 52 that incorporate the Federal permitting program by reference for those jurisdictions where EPA applies part 52.21 as a Federal Implementation Plan because such jurisdictions lack an approved SIP to implement the PSD program. Because today's final rule adds additional paragraphs to the part 52.21 rules, we will be revising the references in subparts C through DDD to appropriately reflect the program that applies. This final action will be taken in a separate **Federal Register** notice and will not change the effective date of today's final changes.

VI. Statutory Authority

The statutory authority for this action is provided by sections 101, 111, 114, 116, and 301 of the CAA as amended (42 U.S.C. 7401, 7411, 7414, 7416, and 7601). This rulemaking is also subject to section 307(d) of the CAA (42 U.S.C. 7407(d)).

List of Subjects in 40 CFR Parts 51 and 52

Environmental protection, Administrative practices and procedures, Air pollution control, Intergovernmental relations.

Dated: August 27, 2003.

Marianne Lamont Horinko,

Acting Administrator.

■ For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 51—[AMENDED]

■ 1. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

Subpart I—[Amended]

■ 2. Section 51.165 is amended:

■ a. By revising paragraph (a)(1)(v)(C)(1).

■ b. By adding paragraphs (a)(1)(xliii) through (xlvi) and paragraph (h).

The revision and additions read as follows:

§ 51.165 Permit requirements.

(a) * * *

(1) * * *

(v) * * *

(C) * * *

(*1*) Routine maintenance, repair and replacement. Routine maintenance, repair and replacement shall include, but not be limited to, any activity(s) that meets the requirements of the equipment replacement provisions contained in paragraph (h) of this section;

* * * * *

(xliii)(A) In general, *process unit* means any collection of structures and/or equipment that processes, assembles, applies, blends, or otherwise uses material inputs to produce or store an intermediate or a completed product. A single stationary source may contain more than one process unit, and a process unit may contain more than one emissions unit.

(B) Pollution control equipment is not part of the process unit, unless it serves a dual function as both process and control equipment. Administrative and warehousing facilities are not part of the process unit.

(C) For replacement cost purposes, components shared between two or more process units are proportionately allocated based on capacity.

(D) The following list identifies the process units at specific categories of stationary sources.

(*1*) For a steam electric generating facility, the process unit consists of those portions of the plant that contribute directly to the production of electricity. For example, at a pulverized coal-fired facility, the process unit would generally be the combination of those systems from the coal receiving equipment through the emission stack (excluding post-combustion pollution controls), including the coal handling equipment, pulverizers or coal crushers, feedwater heaters, ash handling, boiler, burners, turbine-generator set, condenser, cooling tower, water treatment system, air preheaters, and operating control systems. Each separate generating unit is a separate process unit.

(*2*) For a petroleum refinery, there are several categories of process units: those that separate and/or distill petroleum feedstocks; those that change molecular structures; petroleum treating processes; auxiliary facilities, such as steam generators and hydrogen production units; and those that load, unload, blend or store intermediate or completed products.

(*3*) For an incinerator, the process unit would consist of components from the feed pit or refuse pit to the stack, including conveyors, combustion devices, heat exchangers and steam generators, quench tanks, and fans.

(xliv) *Functionally equivalent component* means a component that serves the same purpose as the replaced component.

(xlv) *Fixed capital cost* means the capital needed to provide all the depreciable components. ''Depreciable components'' refers to all components of fixed capital cost and is calculated by subtracting land and working capital from the total capital investment, as defined in paragraph (a)(1)(xlvi) of this section.

(xlvi) *Total capital investment* means the sum of the following: All costs required to purchase needed process equipment (purchased equipment costs); the costs of labor and materials for installing that equipment (direct installation costs); the costs of site preparation and buildings; other costs such as engineering, construction and field expenses, fees to contractors, startup and performance tests, and contingencies (indirect installation costs); land for the process equipment; and working capital for the process equipment.

* * * * *

(h) *Equipment replacement provision.* Without regard to other considerations, routine maintenance, repair and replacement includes, but is not limited to, the replacement of any component of a process unit with an identical or functionally equivalent component(s), and maintenance and repair activities that are part of the replacement activity, provided that all of the requirements in paragraphs (h)(1) through (3) of this section are met.

(1) *Capital Cost threshold for Equipment Replacement.* (i) For an *electric utility steam generating unit,* as defined in § 51.165(a)(1)(xx), the fixed capital cost of the replacement component(s) plus the cost of any associated maintenance and repair activities that are part of the replacement shall not exceed 20 percent of the replacement value of the process unit, at the time the equipment is replaced. For a process unit that is not an electric utility steam generating unit the fixed capital cost of the replacement component(s) plus the cost of any associated maintenance and repair activities that are part of the replacement shall not exceed 20 percent of the replacement value of the process unit, at the time the equipment is replaced.

(ii) In determining the replacement value of the process unit; and, except as otherwise allowed under paragraph (h)(1)(iii) of this section, the owner or operator shall determine the replacement value of the process unit on an estimate of the fixed capital cost of constructing a new process unit, or on the current appraised value of the process unit.

(iii) As an alternative to paragraph (h)(1)(ii) of this section for determining the replacement value of a process unit, an owner or operator may choose to use insurance value (where the insurance value covers only complete replacement), investment value adjusted for inflation, or another accounting procedure if such procedure is based on Generally Accepted Accounting Principles, provided that the owner or operator sends a notice to the reviewing authority. The first time that an owner or operator submits such a notice for a particular process unit, the notice may be submitted at any time, but any subsequent notice for that process unit may be submitted only at the beginning of the process unit's fiscal year. Unless the owner or operator submits a notice to the reviewing authority, then paragraph (h)(1)(ii) of this section will be used to establish the replacement value of the process unit. Once the owner or operator submits a notice to use an alternative accounting procedure, the owner or operator must continue to use that procedure for the entire fiscal year for that process unit. In subsequent fiscal years, the owner or operator must continue to use this selected procedure unless and until the owner or operator sends another notice to the reviewing authority selecting another procedure consistent with this paragraph or paragraph (h)(1)(ii) of this section at the beginning of such fiscal year.

(2) *Basic design parameters.* The replacement does not change the basic design parameter(s) of the process unit to which the activity pertains.

(i) Except as provided in paragraph (h)(2)(iii) of this section, for a process unit at a steam electric generating facility, the owner or operator may select as its basic design parameters either maximum hourly heat input and maximum hourly fuel consumption rate or maximum hourly electric output rate and maximum steam flow rate. When establishing fuel consumption specifications in terms of weight or volume, the minimum fuel quality based on British Thermal Units content shall be used for determining the basic design parameter(s) for a coal-fired electric utility steam generating unit.

(ii) Except as provided in paragraph (h)(2)(iii) of this section, the basic design parameter(s) for any process unit that is not at a steam electric generating

facility are maximum rate of fuel or heat input, maximum rate of material input, or maximum rate of product output. Combustion process units will typically use maximum rate of fuel input. For sources having multiple end products and raw materials, the owner or operator should consider the primary product or primary raw material when selecting a basic design parameter.

(iii) If the owner or operator believes the basic design parameter(s) in paragraphs (h)(2)(i) and (ii) of this section is not appropriate for a specific industry or type of process unit, the owner or operator may propose to the reviewing authority an alternative basic design parameter(s) for the source's process unit(s). If the reviewing authority approves of the use of an alternative basic design parameter(s), the reviewing authority shall issue a permit that is legally enforceable that records such basic design parameter(s) and requires the owner or operator to comply with such parameter(s).

(iv) The owner or operator shall use credible information, such as results of historic maximum capability tests, design information from the manufacturer, or engineering calculations, in establishing the magnitude of the basic design parameter(s) specified in paragraphs (h)(2)(i) and (ii) of this section.

(v) If design information is not available for a process unit, then the owner or operator shall determine the process unit's basic design parameter(s) using the maximum value achieved by the process unit in the five-year period immediately preceding the planned activity.

(vi) Efficiency of a process unit is not a basic design parameter.

(3) The replacement activity shall not cause the process unit to exceed any emission limitation, or operational limitation that has the effect of constraining emissions, that applies to the process unit and that is legally enforceable.

■ 3. Section 51.166 is amended:

■ a. By revising paragraph (b)(2)(iii)(a).

■ b. By adding paragraphs (b)(53) through (56) and paragraph (y).

The revision and additions read as follows:

§ 51.166 Prevention of significant deterioration of air quality.

(b) * * *

(2) * * *

(iii) * * *

(*a*) Routine maintenance, repair and replacement. Routine maintenance, repair and replacement shall include, but not be limited to, any activity(s) that meets the requirements of the equipment replacement provisions contained in paragraph (y) of this section;

* * * * *

(53)(i) In general, *process unit* means any collection of structures and/or equipment that processes, assembles, applies, blends, or otherwise uses material inputs to produce or store an intermediate or a completed product. A single stationary source may contain more than one process unit, and a process unit may contain more than one emissions unit.

(ii) Pollution control equipment is not part of the process unit, unless it serves a dual function as both process and control equipment. Administrative and warehousing facilities are not part of the process unit.

(iii) For replacement cost purposes, components shared between two or more process units are proportionately allocated based on capacity.

(iv) The following list identifies the process units at specific categories of stationary sources.

(*a*) For a steam electric generating facility, the process unit consists of those portions of the plant that contribute directly to the production of electricity. For example, at a pulverized coal-fired facility, the process unit would generally be the combination of those systems from the coal receiving equipment through the emission stack (excluding post-combustion pollution controls), including the coal handling equipment, pulverizers or coal crushers, feedwater heaters, ash handling, boiler, burners, turbine-generator set, condenser, cooling tower, water treatment system, air preheaters, and operating control systems. Each separate generating unit is a separate process unit.

(*b*) For a petroleum refinery, there are several categories of process units: those that separate and/or distill petroleum feedstocks; those that change molecular structures; petroleum treating processes; auxiliary facilities, such as steam generators and hydrogen production units; and those that load, unload, blend or store intermediate or completed products.

(*c*) For an incinerator, the process unit would consist of components from the feed pit or refuse pit to the stack, including conveyors, combustion devices, heat exchangers and steam generators, quench tanks, and fans.

(54) *Functionally equivalent component* means a component that serves the same purpose as the replaced component.

(55) *Fixed capital cost* means the capital needed to provide all the depreciable components. ''Depreciable components'' refers to all components of fixed capital cost and is calculated by subtracting land and working capital from the total capital investment, as defined in paragraph (b)(56) of this section.

(56) *Total capital investment* means the sum of the following: all costs required to purchase needed process equipment (purchased equipment costs); the costs of labor and materials for installing that equipment (direct installation costs); the costs of site preparation and buildings; other costs such as engineering, construction and field expenses, fees to contractors, startup and performance tests, and contingencies (indirect installation costs); land for the process equipment; and working capital for the process equipment.

* * * * *

(y) *Equipment replacement provision.* Without regard to other considerations, routine maintenance, repair and replacement includes, but is not limited to, the replacement of any component of a process unit with an identical or functionally equivalent component(s), and maintenance and repair activities that are part of the replacement activity, provided that all of the requirements in paragraphs (y)(1) through (3) of this section are met.

(1) *Capital Cost threshold for Equipment Replacement.* (i) For an *electric utility steam generating unit,* as defined in § 51.166(b)(30), the fixed capital cost of the replacement component(s) plus the cost of any associated maintenance and repair activities that are part of the replacement shall not exceed 20 percent of the replacement value of the process unit, at the time the equipment is replaced. For a process unit that is not an electric utility steam generating unit the fixed capital cost of the replacement component(s) plus the cost of any associated maintenance and repair activities that are part of the replacement shall not exceed 20 percent of the replacement value of the process unit, at the time the equipment is replaced.

(ii) In determining the replacement value of the process unit; and, except as otherwise allowed under paragraph (y)(1)(iii) of this section, the owner or operator shall determine the replacement value of the process unit on an estimate of the fixed capital cost of constructing a new process unit, or on the current appraised value of the process unit.

(iii) As an alternative to paragraph (y)(1)(ii) of this section for determining

the replacement value of a process unit, an owner or operator may choose to use insurance value (where the insurance value covers only complete replacement), investment value adjusted for inflation, or another accounting procedure if such procedure is based on Generally Accepted Accounting Principles, provided that the owner or operator sends a notice to the reviewing authority. The first time that an owner or operator submits such a notice for a particular process unit, the notice may be submitted at any time, but any subsequent notice for that process unit may be submitted only at the beginning of the process unit's fiscal year. Unless the owner or operator submits a notice to the reviewing authority, then paragraph (y)(1)(ii) of this section will be used to establish the replacement value of the process unit. Once the owner or operator submits a notice to use an alternative accounting procedure, the owner or operator must continue to use that procedure for the entire fiscal year for that process unit. In subsequent fiscal years, the owner or operator must continue to use this selected procedure unless and until the owner or operator sends another notice to the reviewing authority selecting another procedure consistent with this paragraph or paragraph (y)(1)(ii) of this section at the beginning of such fiscal year.

(2) *Basic design parameters.* The replacement does not change the basic design parameter(s) of the process unit to which the activity pertains.

(i) Except as provided in paragraph (y)(2)(iii) of this section, for a process unit at a steam electric generating facility, the owner or operator may select as its basic design parameters either maximum hourly heat input and maximum hourly fuel consumption rate or maximum hourly electric output rate and maximum steam flow rate. When establishing fuel consumption specifications in terms of weight or volume, the minimum fuel quality based on British Thermal Units content shall be used for determining the basic design parameter(s) for a coal-fired electric utility steam generating unit.

(ii) Except as provided in paragraph (y)(2)(iii) of this section, the basic design parameter(s) for any process unit that is not at a steam electric generating facility are maximum rate of fuel or heat input, maximum rate of material input, or maximum rate of product output. Combustion process units will typically use maximum rate of fuel input. For sources having multiple end products and raw materials, the owner or operator should consider the primary product or primary raw material when selecting a basic design parameter.

(iii) If the owner or operator believes the basic design parameter(s) in paragraphs (y)(2)(i) and (ii) of this section is not appropriate for a specific industry or type of process unit, the owner or operator may propose to the reviewing authority an alternative basic design parameter(s) for the source's process unit(s). If the reviewing authority approves of the use of an alternative basic design parameter(s), the reviewing authority shall issue a permit that is legally enforceable that records such basic design parameter(s) and requires the owner or operator to comply with such parameter(s).

(iv) The owner or operator shall use credible information, such as results of historic maximum capability tests, design information from the manufacturer, or engineering calculations, in establishing the magnitude of the basic design parameter(s) specified in paragraphs (y)(2)(i) and (ii) of this section.

(v) If design information is not available for a process unit, then the owner or operator shall determine the process unit's basic design parameter(s) using the maximum value achieved by the process unit in the five-year period immediately preceding the planned activity.

(vi) Efficiency of a process unit is not a basic design parameter.

(3) The replacement activity shall not cause the process unit to exceed any emission limitation, or operational limitation that has the effect of constraining emissions, that applies to the process unit and that is legally enforceable.

PART 52—[AMENDED]

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—[Amended]

■ 2. Section 52.21 is amended:
■ a. By revising paragraph (b)(2)(iii)(*a*).
■ b. By adding paragraphs (b)(55) through (58) and paragraph (cc).

The revision and additions read as follows:

§ 52.21 Prevention of significant deterioration of air quality.

(b) * * *

(2) * * *

(iii) * * *

(*a*) Routine maintenance, repair and replacement. Routine maintenance, repair and replacement shall include, but not be limited to, any activity(s) that meets the requirements of the equipment replacement provisions contained in paragraph (cc) of this section;

* * * * *

(55)(i) In general, *process unit* means any collection of structures and/or equipment that processes, assembles, applies, blends, or otherwise uses material inputs to produce or store an intermediate or a completed product. A single stationary source may contain more than one process unit, and a process unit may contain more than one emissions unit.

(ii) Pollution control equipment is not part of the process unit, unless it serves a dual function as both process and control equipment. Administrative and warehousing facilities are not part of the process unit.

(iii) For replacement cost purposes, components shared between two or more process units are proportionately allocated based on capacity.

(iv) The following list identifies the process units at specific categories of stationary sources.

(*a*) For a steam electric generating facility, the process unit consists of those portions of the plant that contribute directly to the production of electricity. For example, at a pulverized coal-fired facility, the process unit would generally be the combination of those systems from the coal receiving equipment through the emission stack (excluding post-combustion pollution controls), including the coal handling equipment, pulverizers or coal crushers, feedwater heaters, ash handling, boiler, burners, turbine-generator set, condenser, cooling tower, water treatment system, air preheaters, and operating control systems. Each separate generating unit is a separate process unit.

(*b*) For a petroleum refinery, there are several categories of process units: those that separate and/or distill petroleum feedstocks; those that change molecular structures; petroleum treating processes; auxiliary facilities, such as steam generators and hydrogen production units; and those that load, unload, blend or store intermediate or completed products.

(*c*) For an incinerator, the process unit would consist of components from the feed pit or refuse pit to the stack, including conveyors, combustion devices, heat exchangers and steam generators, quench tanks, and fans.

(56) *Functionally equivalent component* means a component that serves the same purpose as the replaced component.

(57) *Fixed capital cost* means the capital needed to provide all the depreciable components. ''Depreciable

components'' refers to all components of fixed capital cost and is calculated by subtracting land and working capital from the total capital investment, as defined in paragraph (b)(58) of this section.

(58) *Total capital investment* means the sum of the following: all costs required to purchase needed process equipment (purchased equipment costs); the costs of labor and materials for installing that equipment (direct installation costs); the costs of site preparation and buildings; other costs such as engineering, construction and field expenses, fees to contractors, startup and performance tests, and contingencies (indirect installation costs); land for the process equipment; and working capital for the process equipment.

* * * * *

(cc) Without regard to other considerations, routine maintenance, repair and replacement includes, but is not limited to, the replacement of any component of a process unit with an identical or functionally equivalent component(s), and maintenance and repair activities that are part of the replacement activity, provided that all of the requirements in paragraphs (cc)(1) through (3) of this section are met.

(1) *Capital cost threshold for equipment replacement.* (i) For an *electric utility steam generating unit,* as defined in § 52.21(b)(31), the fixed capital cost of the replacement component(s) plus the cost of any associated maintenance and repair activities that are part of the replacement shall not exceed 20 percent of the replacement value of the process unit, at the time the equipment is replaced. For a process unit that is not an electric utility steam generating unit the fixed capital cost of the replacement component(s) plus the cost of any associated maintenance and repair activities that are part of the replacement shall not exceed 20 percent of the replacement value of the process unit, at the time the equipment is replaced.

(ii) In determining the replacement value of the process unit; and, except as otherwise allowed under paragraph (cc)(1)(iii) of this section, the owner or operator shall determine the replacement value of the process unit on an estimate of the fixed capital cost of constructing a new process unit, or on the current appraised value of the process unit.

(iii) As an alternative to paragraph (cc)(1)(ii) of this section for determining the replacement value of a process unit, an owner or operator may choose to use insurance value (where the insurance value covers only complete replacement), investment value adjusted for inflation, or another accounting procedure if such procedure is based on Generally Accepted Accounting Principles, provided that the owner or operator sends a notice to the reviewing authority. The first time that an owner or operator submits such a notice for a particular process unit, the notice may be submitted at any time, but any subsequent notice for that process unit may be submitted only at the beginning of the process unit's fiscal year. Unless the owner or operator submits a notice to the reviewing authority, then paragraph (cc)(1)(ii) of this section will be used to establish the replacement value of the process unit. Once the owner or operator submits a notice to use an alternative accounting procedure, the owner or operator must continue to use that procedure for the entire fiscal year for that process unit. In subsequent fiscal years, the owner or operator must continue to use this selected procedure unless and until the owner or operator sends another notice to the reviewing authority selecting another procedure consistent with this paragraph or paragraph (cc)(1)(ii) of this section at the beginning of such fiscal year.

(2) *Basic design parameters.* The replacement does not change the basic design parameter(s) of the process unit to which the activity pertains.

(i) Except as provided in paragraph (cc)(2)(iii) of this section, for a process unit at a steam electric generating facility, the owner or operator may select as its basic design parameters either maximum hourly heat input and maximum hourly fuel consumption rate or maximum hourly electric output rate and maximum steam flow rate. When establishing fuel consumption specifications in terms of weight or volume, the minimum fuel quality based on British Thermal Units content shall be used for determining the basic design parameter(s) for a coal-fired electric utility steam generating unit.

(ii) Except as provided in paragraph (cc)(2)(iii) of this section, the basic design parameter(s) for any process unit that is not at a steam electric generating facility are maximum rate of fuel or heat input, maximum rate of material input, or maximum rate of product output. Combustion process units will typically use maximum rate of fuel input. For sources having multiple end products and raw materials, the owner or operator should consider the primary product or primary raw material when selecting a basic design parameter.

(iii) If the owner or operator believes the basic design parameter(s) in paragraphs (cc)(2)(i) and (ii) of this section is not appropriate for a specific industry or type of process unit, the owner or operator may propose to the reviewing authority an alternative basic design parameter(s) for the source's process unit(s). If the reviewing authority approves of the use of an alternative basic design parameter(s), the reviewing authority shall issue a permit that is legally enforceable that records such basic design parameter(s) and requires the owner or operator to comply with such parameter(s).

(iv) The owner or operator shall use credible information, such as results of historic maximum capability tests, design information from the manufacturer, or engineering calculations, in establishing the magnitude of the basic design parameter(s) specified in paragraphs (cc)(2)(i) and (ii) of this section.

(v) If design information is not available for a process unit, then the owner or operator shall determine the process unit's basic design parameter(s) using the maximum value achieved by the process unit in the five-year period immediately preceding the planned activity.

(vi) Efficiency of a process unit is not a basic design parameter.

(3) The replacement activity shall not cause the process unit to exceed any emission limitation, or operational limitation that has the effect of constraining emissions, that applies to the process unit and that is legally enforceable.

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